FUGITIVE EMISSIONS REPORTING FROM THE PETROLEUM AND NATURAL GAS INDUSTRY

BACKGROUND TECHNICAL SUPPORT DOCUMENT

U.S. ENVIRONMENTAL PROTECTION AGENCY
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(A) Description of Emissions Sources

(1) Segments in the Petroleum and Natural Gas Industry

The U.S. petroleum and natural gas industry encompasses the production of raw gas from wells to the delivery of processed gas to consumers. These steps, and everything in between, use energy and emit greenhouse gases (GHG). It is convenient to view the industry in the following discrete segments:

- Petroleum Industry – petroleum production, petroleum transportation, petroleum refining; and
- Natural Gas Industry –natural gas production, natural gas processing (including gathering and boosting), natural gas transmission and underground storage, and natural gas distribution.

Each industry segment uses common processes and equipment in its facilities, all of which can be related to GHG emissions. Each of these industry segments is described in further detail below.

Petroleum Industry

Petroleum Production. Petroleum or crude oil is produced from underground formations. In some cases, natural gas is also produced from oil production wells; this gas is called associated natural gas. Production may require pumps or compressors for the injection of liquids or gas into the well to maintain production pressure. The produced crude oil is typically separated from water and gas, injected with chemicals, heated, and temporarily stored. GHG emissions from crude oil production result from combustion-related activities and fugitive emissions. Equipment counts and GHG gas emitting practices are related to the number of producing crude oil wells and their production rates.

Petroleum Transportation. The stored crude oil at production sites is either pumped into crude oil transportation pipelines or loaded onto tankers and/or rail freight. Along the way the crude oil may be stored several times in tanks. These practices and storage tanks release fugitive GHG emissions, as well as emissions from combustion. Emissions are related to the amount of crude oil transported and transportation type.

Petroleum Refining. Crude oil is delivered to refineries where it is temporarily stored before it is fractionated by distillation, treated, and the fractions are reformed or cracked to be blended into consumer petroleum products such as gasoline, diesel, aviation fuel, kerosene, fuel oil, and asphalt. These processes are energy intensive. Equipment counts and GHG gas emitting practices are related to the number of and complexity at refineries.

Natural Gas Industry

Natural Gas Production. For natural gas production, wells are used to withdraw raw gas from underground formations. First wells must be drilled to access the underground formations, and often require natural gas well completion or other practices that vent gas from the well depending on the underground formation. The produced raw gas commonly requires treatment in the form of separation of gas/liquids, heating, chemical injection, and dehydration before it is directed into pipelines to the next segment. Combustion and fugitive emissions arise from the wells themselves, gathering pipelines, and all well-site natural gas treatment processes and related equipment and control devices. Determining emissions, equipment counts, and frequency of GHG emitting practices is related to the number of producing wellheads and the amount of produced natural gas. Further details are provided on the individual sources of GHG emissions in Appendix A.

Natural Gas Processing (including Gathering/Boosting stations). In this segment, natural gas from the petroleum and natural gas production segment is compressed and injected into gathering lines that transport it to natural gas processing facilities. In the processing facility, natural gas liquids and various other constituents from the raw gas are separated, resulting in "pipeline quality" gas that is compressed and injected into the transmission pipelines. These separation processes include acid gas removal, dehydration, and fractionation. All equipment and practices have associated GHG fugitive emissions, energy consumption related combustion GHG emissions, and/or process control related GHG emissions. Equipment counts and frequency of GHG emitting practices are related to the number and size of gas processing facilities. Further details are provided on the individual sources of GHG emissions in Appendix A.

Natural Gas Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport natural gas long distances from petroleum and natural gas production sites and natural gas processing facilities to natural gas distribution pipelines or large volume customers such as power plants or chemical plants. Compressor station facilities, which contain large reciprocating and turbine compressors, are used to move the gas throughout the United States transmission pipeline system. Equipment counts and frequency of GHG emitting practices are related to the number and size of compressor stations and the length of transmission pipelines.

Natural gas is also injected and stored in underground formations, or liquefied as liquefied natural gas (LNG) and stored in above ground storage tanks during periods of low demand (e.g., spring or fall), and withdrawn, processed, and distributed during periods of high demand (e.g., winter and summer). Compressors and dehydrators are the primary contributors to emissions from these underground and LNG storage facilities. Equipment counts and GHG emitting practices are related to the number of storage stations. Imported LNG also requires transportation and storage. These processes are similar to above ground LNG storage and require compression and cooling processes. GHG emissions in this segment are related to the number of LNG import terminals and LNG storage facilities. Further details are provided on the individual sources of GHG emissions for all of transmission and storage in the Appendix A.

Natural Gas Distribution. Natural gas distribution pipelines take the high-pressure gas from the transmission pipelines at "city gate" stations, reduce and regulate the pressure, and distribute the gas through primarily underground mains and service lines to individual end users. Between the distribution mains and many offshooting services are underground regulating vaults. GHG emissions from distribution systems are related to the pipelines, regulating stations and vaults, and customer/residential meters. Equipment counts and GHG emitting practices can be related to the number of regulating stations and length of pipelines. Further details are provided on the individual sources of GHG emissions in the Appendix A.

(2) Types of Fugitive Emissions Sources and GHGs

The three main GHGs that are relevant to the petroleum and gas industry are CH_4, CO_2, and N_2O. Of these CH_4 and CO_2 are naturally found in produced natural gas and petroleum, whereas CO_2, CH_4 and N_2O are a result of various combustion processes. Therefore, CH_4 and CO_2 emissions are a result of both fugitive and combustion emissions, whereas N_2O is a result of combustion emissions only. This technical document will focus mainly on CH_4 and CO_2 emissions from fugitive emissions. However, all three gases will be taken into account when developing the threshold analysis.

Emissions from sources in the petroleum and gas industry can be classified into one of two types:

(a) Combustion-related emissions:
Combustion-related emissions result from the use of petroleum and natural gas as fuel in equipment (e.g., heaters, engines, furnaces etc) in the petroleum and gas industry. CO_2 is the predominant combustion-related emission; however, because combustion equipment is rarely 100 percent efficient, CH_4 and N_2O may also be emitted. For methodologies to quantify GHG emissions from combustion, please refer to the Background Technical Support Document (EPA-HQ-OAR-2008-0508-004).

(b) Fugitive emissions:
The Intergovernmental Panel on Climate Change (IPCC) and the Inventory of U.S. GHG Emissions and Sinks[1] (henceforth referred to as the U.S. GHG Inventory) define fugitive emissions to be both intentional and unintentional emissions from systems that extract, process, and deliver fossil fuels. Intentional emissions are emissions designed into the equipment or system. For example, reciprocating compressor rod packing has some amount of emissions by design, e.g., there is a clearance provided between the packing and the compressor rod for free movement of the rod that results in emissions. Also, by design, vent stacks in petroleum and natural gas production, natural gas processing, and petroleum refining facilities release natural gas to the atmosphere. Unintentional emissions result from wear and tear or damage to the equipment. For example, valves result in natural gas emissions due to wear and tear from continuous use over a period of time. Also, pipelines damaged during maintenance operations or corrosion result in unintentional emissions. This document refers to both unintentional emissions and intentional emissions together as fugitive emissions; hereafter referred to as

[1] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006, (April 2008), USEPA #430-R-08-005

"fugitive emissions" or "emissions". This document includes methodologies to quantify fugitive emissions of CO_2 and CH_4.

(3) GHG Emissions from the Petroleum and Natural Gas Industry

Fugitive CH_4 and CO_2 emissions from the petroleum and natural gas industry were 159.6 million metric tons of CO_2 equivalent ($MMTCO_2e$) in 2006. Overall, the natural gas industry emitted 102.4 $MMTCO_2e$ of CH_4 and 28.5 $MMTCO_2e$ of CO_2 in 2006. Total CH_4 and CO_2 emissions from the petroleum industry in 2006 were 28.4 $MMTCO_2e$ and 0.3 $MMTCO_2e$ respectively.

Petroleum Segment

Crude oil production operations accounted for over 97 percent of total CH_4 emissions from the petroleum industry. Crude oil transportation activities accounted for less than one half of a percent of total CH_4 emissions from the oil industry. Crude oil refining processes accounted for slightly over two percent of total CH_4 emissions from the petroleum industry because most of the CH_4 in crude oil is removed or escapes before the crude oil is delivered to the petroleum refineries. The United States currently estimates CO_2 emissions from crude oil production operations only in the U.S. GHG Inventory. Research is underway to include other larger sources of fugitive CO_2 emissions in future inventories.

Natural Gas Segment

Emissions from natural gas production accounted for approximately 27 percent of CH_4 emissions and about 25 percent of non-energy CO_2 emissions from the natural gas industry in 2006. Processing facilities accounted for about 12 percent of CH_4 emissions and approximately 74 percent of fugitive CO_2 emissions from the natural gas industry. CH_4 emissions from the natural gas transmission and storage segment accounted for approximately 37 percent of emissions, while CO_2 emissions from natural gas transmission and storage accounted for less than 1 percent of the CO_2 emissions from the natural gas industry. Natural gas distribution segment emissions, which account for approximately 24 percent of CH_4 emissions from natural gas systems and less than 1 percent of CO_2 emissions, result mainly from fugitive emissions from gate stations and pipelines.

(4) Methodology for Selection of Industry Segments and Emissions Sources Feasible for Inclusion in a Mandatory GHG Reporting Rule

It is important to develop criteria to help identify those emissions sources in the petroleum and natural gas industry most likely to be of interest to policymakers from a GHG emissions perspective. To identify sources for potential inclusion in the proposed rule two preliminary steps were taken; 1) review existing regulations to identify emissions sources already being regulated, and 2) review existing programs and guidance documents to identify a comprehensive list of emissions sources for potential inclusion in the proposed rule.

The first step in determining emissions sources amenable to inclusion in a mandatory GHG reporting rule was to review existing regulations that the industry is subject to. Reviewing existing reporting requirements highlighted those sources that are currently subject to regulation for other pollutants and may be good candidates for addressing GHG emissions.

The second step was to establish a comprehensive list of emissions sources from the various existing programs and guidance documents on GHG emissions reporting. This helped in avoiding any missing emissions sources already being monitored for reporting under other program(s). Both of these steps are described below.

(a) Review of Existing Regulations

The first step was to understand existing regulations and consider adapting elements of the existing regulations to a mandatory reporting rule for GHG emissions. At this time, there are two emissions reporting regulations and six emissions reduction regulations in place for the petroleum and natural gas industry, including one voluntary reporting program included in the Code of Federal Regulations. Table 1 provides a summary of each of these six regulations.

Table 1: Summary of Regulations Related to the Petroleum and Natural Gas Industry

Regulation	Type	Point/ Area/ Mobile Source	Gases Covered	Segment and Sources
EPA 40 CFR Part 51 – Consolidated Emissions Reporting	Emissions Reporting	Point, Area, Mobile, Biogenic	VOCs, NOx, CO, NH_3, PM_{10}, $PM_{2.5}$	All segments of the petroleum and gas industry
DOE 10 CFR Part 300 – Voluntary GHG Reporting	Voluntary GHG Reporting	Point, Area, Mobile	CO_2, CH_4, N_2O, HFCs, PFCs, , SF_6, and CFCs	All segments of the petroleum and gas industry
EPA 40 CFR Part 60, Subpart KKK	Standards of Performance	Point	VOCs	Onshore processing plants; sources include compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit located in the plant
EPA 40 CFR Part 60, Subpart LLL	Standards of Performance	Point	SO_2	Onshore processing plants; Sweetening unit, and sweetening unit followed by a sulfur recovery unit
EPA 40 CFR Part 63 – NESHAP[1] – RIN 2060-AE34	MACT[3]	Point (Glycol dehydrators, natural gas transmission and storage facilities)	HAPs	Glycol dehydrators
EPA 40 CFR Part 63 – NESHAP[1] – RIN 2060-AM16	MACT[3]	Point and Area (petroleum and gas production, up to and including processing plants)	HAPs	Point Source - Glycol dehydrators and tanks in petroleum and gas production; equipment leaks at gas processing plants Area Source - Triethylene glycol (TEG) dehydrators in petroleum and gas production

EPA 40 CFR Part 63 – NESHAP[1] – RIN 2060 AG - 67	MACT[3]	Point (Stationary Combustion Turbine)	HAPs	All segments of the petroleum and gas industry
EPA 40 CFR Part 63 – NESHAP[1] – RIN 2060 AG-63	MACT[3]	Point (Reciprocating Internal Combustion Engines)	HAPs	All segments of the petroleum and gas industry
Notes: [1]National Emission Standards for Hazardous Air Pollutants [2]New Source Performance Standard [3]Maximum Allowable Control Technology				

From Table 1, it can be observed that only DOE 10 CFR Part 300 includes the monitoring or reporting of CH_4 emissions (or other GHGs). However, this program is a voluntary reporting program and is not expected to have a comprehensive coverage of CH_4 emissions. Although some of the sources included in the other regulations lead to CH_4 emissions, these emissions are not reported. The MACT regulations do not require any monitoring of emissions. Hence there is no reporting of emissions, only reductions. This review of existing regulations concludes that fugitive GHG emissions from oil and gas operations are not systematically monitored and reported; therefore these regulations and programs can not serve as the foundation for a mandatory reporting rule.

(b) Review of Existing Programs

The second step was to review existing monitoring and reporting programs to identify all emissions sources that are already monitored under these programs. At this time, there are six reporting programs and six guidance documents that were reviewed. Table 2 provides a summary of the points of monitoring identified by the programs and guidance documents.

Table 2 shows that the different monitoring programs and guidance documents reflect the points of monitoring identified in the U.S. GHG Inventory, which are consistent with the range of sources covered in the 2006 IPCC Guidelines. Therefore, the U.S. GHG Inventory was used to provide a list of emissions sources as a starting point for determining the emissions sources that can be potentially included in the proposed rule.

The preliminary review exercise provided a potential list of sources, but did not yield any definitive indication on the emissions sources that were most suitable for potential inclusion in a reporting program. A systematic assessment of emissions sources in the oil and gas industry was then undertaken to identify the specific emissions sources (e.g., equipment or component) that are of greatest interest for inclusion in a mandatory GHG reporting rule.

Table 2: Summary of Program and Guidance Documents on GHG Emissions Monitoring and Reporting

Reporting Program/Guidance	Source Category (or Fuel)	Coverage (Gases or Fuels)	Points of Monitoring	Monitoring Methods and/or GHG Calculation Methods*
2006 IPCC Guidelines for National GHG Inventory, Volume 2, Chapter 4	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	Oil and natural gas systems fugitive equipment leaks, evaporation losses, venting, flaring, and accidental releases; and all other fugitive emissions at oil and natural gas production, transportation, processing, refining, and distribution facilities from equipment leaks, storage losses, pipeline breaks, well blowouts, land farms, gas migration to the surface around the outside of wellhead casing, surface casing vent bows, biogenic gas formation from tailings ponds and any other gas or vapor releases not specifically accounted for as venting or flaring	Accounting/ reporting methodologies and guidelines Companies choose a base year for which verifiable emissions data are available. The base year emissions are used as an historic control against which the company's emissions are tracked over time. This ensures data consistency over time. Direct measurement of GHG emissions by monitoring concentration and flow rate can also be conducted. IPCC methodologies are broken down into the following categories: - Tier I calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and default industry segment emission factors - Tier II calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and country-specific industry segment emission factors or by performing a mass balance using country-specific oil and/or gas production information Tier III calculation-based methodologies for estimating emissions involve "rigorous bottom-up assessment by primary type of source (e.g. evaporation losses, equipment leaks) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. The calculation of emissions is based on activity data and facility-specific emission factors
AGA - Greenhouse Gas Emissions Estimation Methodologies, Procedures, and Guidelines	Gas – Distribution	CH_4, non-combustion CO_2 and other GHG gases	Segment-level counts, equipment discharges (i.e. valves, open-ended lines, vent stacks), and segment	Equipment or segment emissions rates and engineering calculations Tier I, II (IPCC) - facility level emissions rates

for the Natural Gas Distribution Sector			capacities, facility counts and capacities	Tier III (IPCC) - equipment emissions rates for intentional fugitives, process level emissions rates, and process/equipment level emissions rate
API - Compendium of GHG Emissions Estimation Methodologies for the Oil and Gas Industry	Gas and Petroleum – all segments	CH_4, non-combustion CO_2	Equipment discharges (e.g. valves, open-ended lines, vent stacks), vent stacks for equipment types, tank PRV/vents, and facility input	Equipment or segment emissions rates and engineering calculations Tier II (IPCC) - facility level emissions rates Tier III (IPCC) - equipment emissions rates for intentional fugitives, process level emissions rates, tank level emissions rates, and process/equipment level emissions rate (BY SEGMENT)
California Climate Action Registry General Reporting Protocol, March 2007	All legal entities (e.g. corporations, institutions, and organizations) registered in California, including petroleum and gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in indirect and direct emission of GHG gases for the entity	Provides references for use in making fugitive calculations The CCAR does not specify methodology to calculate fugitive emissions
California Mandatory GHG Reporting Program	Petroleum – Refineries	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in CH_4 and CO_2 fugitive emissions for petroleum refineries	Continuous monitoring methodologies and equipment or process emissions rates. CO_2 process emissions can be determined by continuous emissions monitoring systems. Methods for calculating fugitive emissions and emissions from flares and other control devices are also available.
DOE Voluntary Reporting of Greenhouse Gases Program (1605(b))	Petroleum and Gas- All Segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in direct and indirect emissions of GHG gases for the corporation or organization	Direct, site-specific measurements of emissions or all mass balance factors. Mass-balance approach, using measured activity data and emission factors that are publicly documented and widely reviewed and adopted by a public agency, a standards-setting organization or an industry group. Mass-balance approach, using measured activity data

				and other emission factors Mass balance approach using estimated activity data and default emissions factors.
EU ETS 1st and 2nd Reporting Period	Petroleum – Refining	Non-combustion CO_2	Hydrogen production	Engineering calculations Operators may calculate emissions using a mass-balance approach
INGAA - GHG Emissions Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1	Gas - Transmission/Storage	CH_4, non-combustion CO_2	Segment-level counts, equipment discharges (i.e. valves, open-ended lines, vent stacks), and segment capacities, facility counts and capacities	Equipment or segment emissions rates Tier I (IPCC)- segment level emissions rates from intentional and unintentional releases Tier II - equipment level emissions rates for intentional releases Tier II (IPCC) – facility and equipment level emissions rates for unintentional leaks Engineering calculation methodologies for: - Pig traps - Overhauls - Flaring
IPIECA - Petroleum Industry Guidelines for Reporting GHG Emissions	Petroleum and Gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	Refers to API Compendium points of monitoring: Equipment discharges (e.g. valves, open-ended lines, vent stacks), vent stacks for equipment types, tank PRV/vents, and facility input	Tiers I, II, and III (IPCC) definitions and reporting methods for all fugitive GHG emissions in the oil and gas industry
New Mexico GHG Mandatory Emissions Inventory	Petroleum refineries	CO_2 reporting starts 2008 , CH_4 reporting starts 2010	Equipment discharges (e.g. valves, pump seals, connectors, and flanges)	- 2009 reporting procedures will be made available in 10/2008

The Climate Registry (General Reporting Protocol for the Voluntary Reporting Program), 2007	All legal entities (e.g. corporations, institutions, and organizations) including petroleum and gas – all segments	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in emission of GHG gases for the entity	Continuous monitoring methodologies and equipment or process emissions rates Measurement-based methodology monitor gas flow (continuous, flow meter) and test methane concentration in the flue gas. Calculation-based methodologies involve the calculation of emissions based on activity data and emission factors.
Western Regional Air Partnership (WRAP)	Petroleum and Gas – Production	VOC	Gas and oil wells	Equipment and process emissions rates Emissions are quantified by calculation based method using emission factors and activity factors. Methods used are specified in chapter 2
World Resources Institute/ World Business Council for Sustainable Development GHG Protocol Corporate Standard, Revised Edition 2003	Organizations with operations that result in GHG (GHG) emissions e.g. corporations (primarily), universities, NGOs, and government agencies. This includes the oil and gas industry	CH_4, non-combustion CO_2 and other GHG gases	All activities resulting in direct and indirect emission of GHG gases for the corporation or organization	Provides continuous monitoring methodologies and equipment or process emissions rates. Companies need to choose a base year for which verifiable emissions data are available and specify their reasons for choosing the year. "The base year emissions are used as an historic datum against which the company's emissions are tracked over time. Emissions in the base year should be recalculated to reflect a change in the structure of the company, or to reflect a change in the accounting methodology used. This ensures data consistency over time." Direct measurement of GHG emissions by monitoring concentration and flow rate can be conducted. Calculation-based methodologies for estimating emissions involve the calculation of emissions based on activity data and emission factors

(c) Selection of Emissions Sources for Reporting

A key challenge in identifying emissions sources for inclusion in a mandatory reporting rule is answering two related questions. The first is defining a facility. In other words, physically what constitutes a facility? The second is determining which sources of emissions should a facility report? It is difficult to include or exclude sources from a mandatory reporting rule without knowing the definition of a facility. Therefore, to resolve this interdependence, both the facility definition and emissions source inclusion (or exclusion) was studied independently and finally reviewed together to arrive at a conclusion.

(i) Facility Definition Characterization

Typically, the various regulations under the Clean Air Act (CAA) define a facility as a group of emissions sources all located in a contiguous area and under the control of the same person (or persons under common control). This definition can be easily applied to onshore natural gas processing and petroleum refining facilities since the operations are all located in a clearly defined boundary. Onshore natural gas transmission stations also can be clearly identified using this definition. However, this definition does not easily lend itself to onshore petroleum and natural gas production, onshore natural gas transmission pipelines and natural gas distribution, and the petroleum transportation segments of the industry.

Petroleum and natural gas production facilities can be very diverse in arrangement. Sometimes crude oil and natural gas producing wellheads are far apart with individual equipment at each wellhead. At other times several wells in close vicinity are connected to common pieces of equipment. The choice of whether multiple wells are connected to common equipment depends on factors such as distance between wells, production rate, and ownership and royalty payment. New well drilling techniques such as horizontal and directional drilling allow for multiple wellheads to be located at a single location (or pad) from where they are drilled to connect to different zones in the same reservoir. Therefore, finding a single definition of a facility that can be applied to all of onshore petroleum and natural gas production can be challenging. In addition there are several hydrocarbon resource ownership and operational equipment ownership issues relating to the onshore petroleum and natural gas production segment. In many cases the mineral rights are not necessarily owned by the land owner. This is prevalent mostly in the western half of the United States where the Bureau of Land Management owns major portions of the minerals rights whereas the lands are held by private owners. Also, in many cases multiple operators operate in a single production operation. For example, in some cases in the onshore production segment, multiple operators are responsible for different equipment in the same field under different ownership. Such cases of multiple owner/ operators further complicate assigning responsibilities of facilities for emissions reporting.

Natural gas transmission and petroleum transportation pipelines run over several hundred thousand miles in the United States. There are no identifiers (or markers) that can be used to readily assign a portion of the pipelines as a single facility. Moreover, emissions sources in pipelines are spread across large geographical areas making it difficult to use the common definition available from the CAA. The natural gas distribution segment has issues similar to the onshore natural gas transmission segment in defining facilities for the extensive pipeline network. The meters and regulators in the distribution segment are mainly in small underground vaults in urban areas. Individually defining each vault as a facility is again impractical owing to the size and expected magnitude of emissions from a single vault. It may also not be immediately obvious to include multiple vaults to define a facility, as they are not in a contiguous area.

(ii) Selection of Potential Emissions Sources for Reporting

Given that there are over 160 emissions sources in the petroleum and gas industry, it is important to target those sources that contribute significantly to total emissions from the industry nationally. This is to avoid unnecessary reporting burden on the industry, but at the same time to enable maximum coverage for emissions reporting. The selection of emissions sources for inclusion in the proposed rulemaking was conducted in three steps.

Step 1: Characterize Emissions Sources

The U.S. GHG Inventory was used as the complete list of sources under consideration for inclusion in a reporting rule. The U.S. GHG Inventory was also used to provide all relevant emissions source characteristics like type and number of sources across industry segments and geographic location, emissions per unit of output, total national emissions from each emissions source, and frequency of emissions. Also, information included in the U.S. GHG Inventory and the Natural Gas STAR Program technical studies were used to identify the different monitoring methods that are considered best practice for each emissions source. If there is more than one monitoring method available, each of which is equivalent in monitoring capabilities, then the one with lower economic burden was considered in the analysis.

Step 2: Identify Selection Criteria and Develop Decision Tree for Selection

There are several factors that impact the decision on whether an emissions source could be included. A discussion of the factors follows below.

- *Contribution to U.S. GHG Inventory* – Emissions sources that contribute significantly large emissions nationally can be considered for potential inclusion in a rule, since they increase the coverage of emissions reporting. Where emissions from a source were greater than one percent of the total national emissions from the petroleum or natural gas industry they were considered to be a significant source. The U.S. GHG Inventory estimates emissions from the natural gas industry and petroleum industry separately. The one percent significance refers to a percentage of emissions from each source to its respective inventory total emissions. For example, a source in the natural gas industry is significant if its national emissions are equal to or greater than one percent of total fugitive emissions from all sources only in the natural gas industry.
- *Emissions per Unit* – There are some emissions sources that may not contribute significantly to national emissions, but emissions per unit of activity for the source may be large enough that even a one time occurrence could lead to significant emissions. For example, emergency releases from equipment and vessels are not frequent nor are they necessarily significant on a national level, but the one time emissions are significant. Therefore, those sources with significant emissions per unit, i.e. over 100 Mcf/unit/year, could be considered for inclusion in a reporting rule.

- *Best Practice Monitoring Method(s)* – Depending on the types of monitoring method typically undertaken, a source may or may not be a potential for emissions reporting. There are four types of monitoring methods as follows;
  - Continuous monitoring – refers to cases where technologies are available that continuously monitor either the emissions from a source or a related parameter that can be used in estimating emissions. For example, continuous monitoring sensors can determine the flow rate and composition of exhaust gases from a combustion process. On the other hand, fuel meters monitor the amount of fuel consumed in combustion equipment that can be used to estimate the amount of emissions.
  - Periodic monitoring – refers to monitoring at periodic intervals to determine emissions from sources. For example, leak detection and measurement equipment can be used on a recurring basis to identify and measure leaks from equipment.
  - Engineering calculations – refers to estimation of emissions using engineering parameters. For example, emissions from a vessel emergency release can be estimated by calculating the volume of the vessel that the emissions gas occupies.
  - Emissions factors – refers to utilizing an existing emissions rate for a given source and multiplying it by the relevant activity data to estimate emissions. For example, emissions per equipment unit per year can be multiplied by the number of pieces of equipment in a facility to estimate annual emissions from that equipment for the facility.

By utilizing the various factors that relate to selection of potential sources, a decision process was developed to identify the potential sources that could be included in a reporting rule. Figure 1 shows the resulting decision tree that includes these criteria and supported the decision-making process.

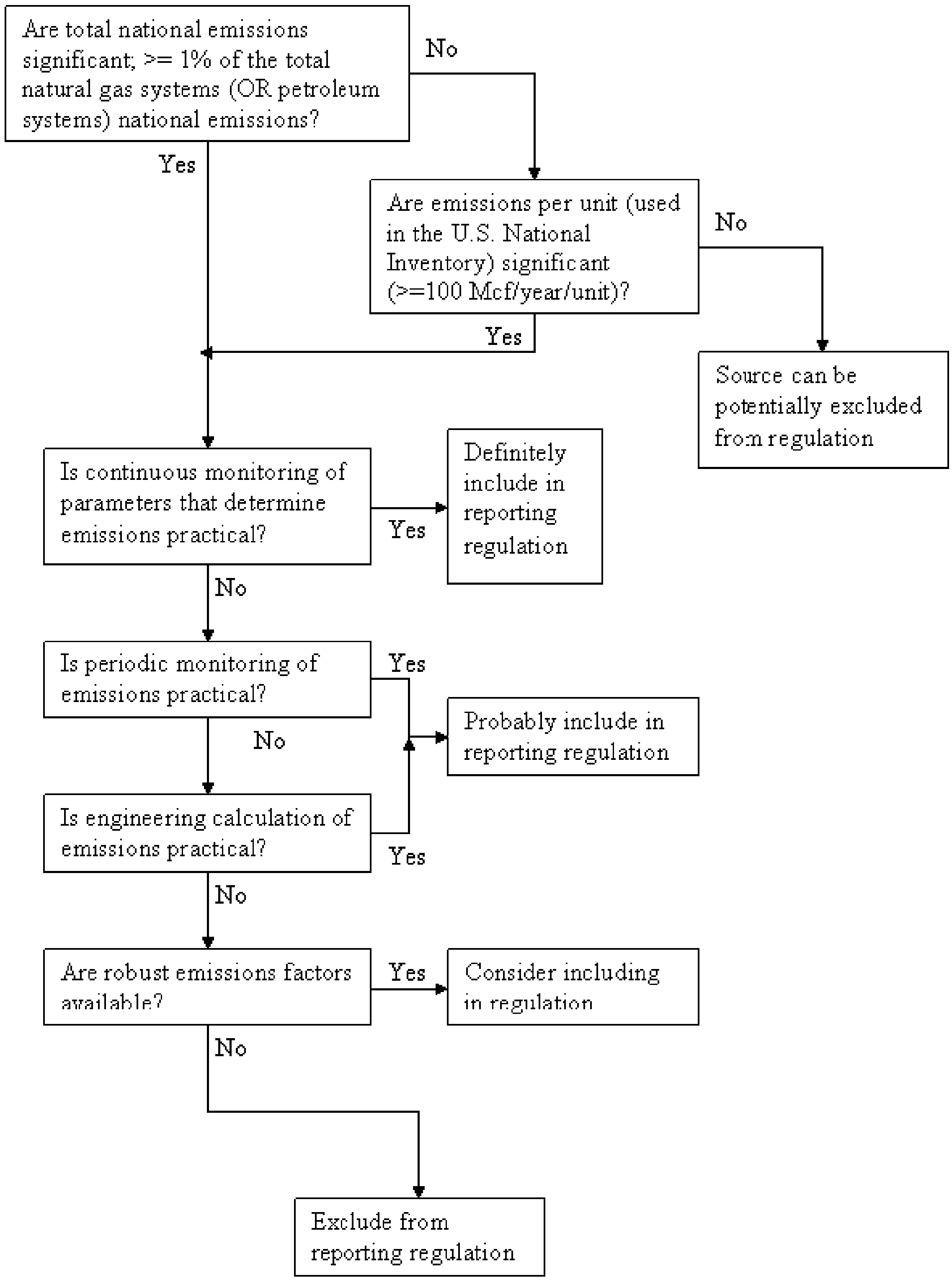

Figure 1: Decision Process for Emissions Source Selection

The decision process provided in Figure 1 was applied to each emissions source in the natural gas industry inventory and petroleum industry inventory. Only methane emissions were taken into consideration for this exercise given that, for most sources, fugitive CO_2 emissions are negligible in comparison to CH_4 emissions from the same sources. The emissions sources were then segregated into four categories; “definitely include”, “probably include”, “consider including”, and “exclude”.

(iii) Address Sources with Large Uncertainties

The natural gas and petroleum industry inventories are based on a U.S. EPA and Gas Research Institute Study[2] published in 1996. There are several estimates of emissions factors for emissions sources that do not correctly reflect the operational practices of today. Hence in some cases the estimates are under or over accounting the amount of emissions from these sources. From anecdotal evidence from the industry, it is believed that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory. In most cases sufficient information is not publicly available to make changes to the estimates. In other cases where public data are available, it is often incomplete and does not represent the industry at a national level. The decision tree was not necessarily ideal for sources known to be over- or underestimated in current inventories, which use existing emission factors. Therefore, the decision tree was overridden for these sources. The sources added for consideration under this exception are:

- Condensate and oil storage tanks
- Natural gas well workovers
- Natural gas well completions
- Natural gas well blowdowns,
- Flares

In addition, the U.S. GHG Inventory includes fugitive CH_4 and CO_2 emissions from natural gas engines and turbines, as well as petroleum refineries. Emissions from these sources were not considered further here because methods for calculating and reporting emissions from these sources are addressed in the background technical support documents for Stationary Combustion (EPA-HQ-OAR-2008-0508-004) and Petroleum Refineries (EPA-HQ-OAR-2008-0508-025), respectively.

(iv) Identify Sources to be Included

Based on the understanding of facility definitions for each segment of the oil and gas industry and the identification of potential sources for inclusion in a mandatory reporting rule, the potential segments and sources to be included were identified. A brief analysis for each segment is as follows;

§ *Onshore Petroleum and Natural Gas Production Segment* – Onshore production operations are a challenge for emissions reporting using the conventional facility definition of a contiguous area under a common owner/ operator. This is because

[2] U.S. Environmental Protection Agency/ Gas Research Institute, Methane Emissions from the Natural Gas Industry, June 1996.

multiple operators and equipment share the same operation. A possible solution to this issue is to define a hydrocarbon producing basin as a facility and all operators report their emissions on a basin level. In such a case, the company (or corporation) operating in multiple fields in the same basin can report at the basin level. Reporting of emissions from all potential emissions sources at a basin level will substantially increase reporting burden. However, complexity of reporting requirements will substantially be reduced if companies are reporting at basin level.

One way to reduce the reporting burden due to the large number of sources in the production segment would be to focus on the largest contributors to GHG emissions. From the EPA Natural Gas STAR experience in mitigating methane emissions in the onshore oil and gas production segment, the major contributors to emissions from the onshore production segment are easily identifiable. These emissions sources are not reflected as major sources in the U.S. GHG Inventory as the inventory estimates are based on a 1992 measurement study[2] that, in the case of these sources, was incomplete. Based on current knowledge of the petroleum and natural gas industry, the following seven emissions sources are known to be the major contributors to the total petroleum and natural gas production segment fugitive emissions; natural gas driven pneumatic valve and pump devices, well completion releases and flaring, well blowdowns, well workovers, crude oil and condensate storage tanks, dehydrator vent stacks, and reciprocating compressor rod packing. With a basin level facility definition, onshore production segment operators or companies could report emissions from the seven major emissions sources listed above.

Other options, like defining a single wellhead as a facility or defining all equipment from wellhead to compression as a facility is more challenging, as these options could lead to complex reporting requirements. This also could significantly increase the number of reporters to a program, and potentially raise implementation issues.

Onshore petroleum and natural gas production would seem to be an important segment for inclusion in a GHG reporting program, due to its relatively large share of emissions. However, in order to include this segment, there are challenges that would have to be overcome in defining what is a facility, and therefore, who is the reporter. For some segments of the industry, identifying a facility is straightforward since there are clear physical boundaries and ownership structures that lend themselves to identifying the scope of reporting and responsible reporting entities (e.g., onshore natural gas processing facilities, natural gas transmission compression facilities, and offshore petroleum and natural gas facilities). This is not the case for onshore petroleum and natural gas production and therefore defining a facility is possible but more complex.

Given these complexities, this document does not include any further analysis on this segment. However, this is an important area for additional research.

§ *Offshore Petroleum and Natural Gas Production Segment* – All of the production activities offshore take place on platforms. These platforms can be grouped into two main categories; wellhead platforms and processing platforms. Wellhead platforms consist of crude oil and/ or natural gas producing wellheads that are connected to processing platforms or send the hydrocarbons onshore. Processing platforms consist of wellheads as well as processing equipment such as separators and dehydrators, in addition to compressors. All platforms are within a confined area and can be distinctly identified as a facility. Since all sources are within a small area on and around the platform, all sources of emissions on or associated with offshore platforms could be monitored and reported.

§ *Onshore Natural Gas Processing Segment* – There are two types of operations in the processing segment of the natural gas industry; gathering/ boosting stations and processing facilities. Gathering/ boosting stations typically collect gas from several producing zones, dehydrate the natural gas and compress it for transportation to onshore natural gas processing plants. Processing facilities further process the gas to remove hydrogen sulfide (H_2S) and/ or CO_2 in the natural gas, if any, separate the higher hydrocarbons (ethane, propane, butane, pentanes, etc.) from the natural gas and compress the natural gas to be injected into the onshore natural gas transmission segment. Both gathering/ boosting stations and natural gas processing facilities have a well defined boundary within which all processes take place, hence there is no ambiguity in defining them as a facility. Monitoring in an onshore natural gas processing facility entails leak detection and survey facility wide. Hence all emissions sources in the processing plant could be monitored and included in a mandatory GHG reporting rule, including associated gathering and boosting stations.

§ *Onshore Natural Gas Transmission Segment* – Transmission compressor stations are easily identifiable as a facility with all compressors and related equipment confined to a defined boundary. Hence, transmission compressor stations are viable candidates for inclusion in a mandatory GHG reporting rule. However, inclusion of transmission pipelines in a mandatory reporting rule would be challenging due to the difficulty in defining pipelines as a facility and the spread of emissions sources over large geographical areas.

§ *Underground Natural Gas Storage, LNG Storage, and LNG Import Segments* – All operations in an underground natural gas storage facility (except wellheads), LNG storage facility, and LNG import facility are confined within defined boundaries. In the case of underground natural gas storage facilities, the wellheads are within short distances of the main compressor station such that it is feasible to monitor them along with the stations themselves. Since a facility is clearly defined in each case, all three segments could be included in a mandatory reporting rule.

§ *Natural Gas Distribution Segment* – The distribution segment meter and regulation vaults are identifiable as a facility. However, the magnitude of emissions from a single vault is not significant. Although vaults collectively contribute to a significant share of emissions from the natural gas industry nationally, it may not be possible to group multiple vaults as a single facility as they are not in a contiguous area. Also, emissions from vaults and pipelines are usually quickly dealt with given the safety concerns in a gas distribution segment. This might not allow any time for monitoring of leaks. These issues would likely have to be addressed before distribution segment emissions sources could be included in a mandatory GHG reporting rule.

§ *Petroleum Transportation Segment* – All the sources in the petroleum transportation segment were excluded as a result of the decision process. Hence, this segment may not be amenable to inclusion in a reporting program. Moreover, petroleum pipelines face the same problem in terms of facility definition as onshore natural gas transmission pipelines.

Table 3 provides a list of each segment and a corresponding facility definition. It also provides a listing of all sources that can be monitored and could be reported as part of a mandatory GHG reporting rule.

Table 3: Segment Specific Facility Definition

Segment	Facility Definition	Potential Emissions Sources for Inclusion
Offshore Petroleum and Natural Gas Production	Any platform structure, floating in the ocean, fixed on ocean bed, or located on artificial islands in the ocean, that houses equipment to extract hydrocarbons from the ocean floor and transports it to storage or transport vessels or onshore. In addition, offshore production facilities may include equipments for separation of liquids from natural gas components, dehydration of natural gas, extraction of H_2S and CO_2 from natural gas, crude oil and condensate storage tanks, both on the platform structure and floating storage tanks connected to the platform structure by a pipeline, and compression or pumping of hydrocarbons to vessels or onshore. The facilities under consideration are located in both State administered waters and Mineral Management Services administered Federal waters.	Acid gas removal (AGR) vent stacks, centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, flare stacks, natural gas driven pneumatic pumps, non-pneumatic pumps, open-ended lines (OELs), pump seals, offshore platform pipeline fugitive emissions, platform fugitive emissions, natural gas driven pneumatic manual valve actuator devices, natural gas driven pneumatic valve bleed devices, reciprocating compressor rod packing, and storage tanks.
Onshore Natural Gas Processing	Any processing site engaged in the extraction of natural gas liquids from produced natural gas, which may also include fractionation of mixed Natural Gas Liquids (NGL) to natural gas products, removal of contaminants such as carbon dioxide, sulfur compounds, nitrogen, helium, and water. In addition, processing facilities encompass gathering and boosting stations that include equipment that separate natural gas liquids from natural gas, dehydrate the natural gas, and transport the natural gas to transmission pipelines or to a processing facility with fractionation equipment.	AGR vent stacks, blowdown vent stacks, centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, open-ended lines (OELs), natural gas driven pneumatic manual valve actuator devices, natural gas driven pneumatic valve bleed devices, processing facility fugitive emissions, reciprocating compressor rod packing, and storage tanks.

Onshore Natural Gas Transmission	Any permanent combination of compressors that move natural gas at increased pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage facilities. In addition, transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and storage of water and hydrocarbon liquids.	Centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, OELs, natural gas driven pneumatic manual valve actuator devices, natural gas driven pneumatic valve bleed devices, reciprocating compressor rod packing, storage tanks, and transmission station fugitive emissions.
Underground Natural Gas Storage	Any subsurface facility utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at an underground storage facility include, but are not limited to, compression, dehydration and flow measurement. The storage facility also includes all the wellheads connected to the compression units located at the facility.	Centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, dehydrator vent stacks, OELs, pump seals, natural gas driven pneumatic manual valve actuator devices, natural gas driven pneumatic valve bleed devices, reciprocating compressor rod packing, storage tanks, storage station fugitive emissions, and storage wellhead fugitive emissions.
LNG Storage Facilities	Any onshore facility that stores liquefied natural gas in above ground storage vessels. The facility may include equipment for liquefying natural gas, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.	Centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, OELs, LNG storage station fugitive emissions, and reciprocating compressor rod packing.
LNG Import Facilities	Any onshore and/or offshore facilities that receive imported liquefied natural gas, store it in storage tanks, re-gasify it, and deliver re-gasified natural gas to natural gas transmission or distribution systems. The facilities include tanker unloading equipment, liquefied natural gas transportation pipelines, pumps, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.	Centrifugal compressor dry seals, centrifugal compressor wet seals, compressor fugitive emissions, OELs, LNG storage station fugitive emissions, and reciprocating compressor rod packing.

(B) Options for Reporting Threshold

For each segment in the petroleum and natural gas industry identified above as amenable to a reporting program, four thresholds were considered for emissions reporting as applicable to an individual facility; 1,000 metric tons of CO_2 equivalent ($mtCO_2e$) per year, 10,000 $mtCO_2e$, 25,000 $mtCO_2e$, and 100,000 $mtCO_2e$. A threshold analysis was then conducted on each segment to determine which level of threshold was most suitable for each industry segment. CH_4, CO_2, and N_2O emissions from each segment were included in the threshold analysis.

(1) Threshold Analysis

For each segment, a threshold analysis was conducted to determine how many of the facilities in the segment exceed the various reporting thresholds, and the total emissions from these impacted facilities. This analysis was conducted considering fugitive CH_4 and CO_2 emissions, and combustion CH_4, CO_2, and N_2O emissions. The fugitive emissions estimates available from the U.S. GHG Inventory were used in the analysis. Combustion emissions were estimated using gas engine methane emissions factors available from the GRI study, back calculating the natural gas consumptions in engines, and finally applying a CO_2 emissions factor to the natural gas consumed as fuel. N_2O emissions were also calculated similarly. In the case of offshore petroleum and natural gas production platforms combustion emissions are already available from the GOADS 2000 study analysis and hence were directly used for the threshold analysis.

The general rationale for selecting a reporting threshold could be to identify a level at which the incremental emissions reporting between thresholds is the highest for the lowest incremental increase in number of facilities reporting between the same thresholds. This would ensure maximum emissions reporting coverage with minimal burden on the industry. For example, for offshore production the emissions reporting coverage is 31 percent and the corresponding reporting facilities coverage is 0.2 percent for a threshold of 100,000mtCO_2e per year. The incremental emissions and facilities coverage is 20 and 1.8 percent (51 percent minus 31 percent and 2 percent minus 0.2 percent), respectively, for a 25,000 mtCO_2e per year threshold. However, at the next reporting threshold level of 10,000 mtCO_2e per year the incremental emissions and entities coverage is 16 and 4 percent, respectively. It can be seen that the incremental coverage of emissions decreases but the coverage of facilities increases.

Table 4 provides the details of the threshold analysis at all threshold levels for the different segments in the oil and gas industry.

Table 4: Threshold Analysis for the Oil and Gas Industry Segments

				Emissions Covered				Facilities Covered	
Source Category	Threshold Level	Total National Emissions	Number of Facilities	Process Emissions ($mtCO_2e$/year)	Combustion CO_2 Emissions (mt/year)	Total Emissions (tons $mtCO_2e$/yr)	Percent	Number	Percent
Offshore Petroleum and Natural Gas Production Facilities	100,000	10,162,179	2,525	2,931,777	204,408	3,136,185	31%	4	0.2%
	25,000	10,162,179	2,525	3,969,694	1,168,382	5,138,076	51%	50	2%
	10,000	10,162,179	2,525	4,678,145	2,095,741	6,773,885	67%	156	6%
	1,000	10,162,179	2,525	5,951,766	3,831,730	9,783,496	96%	1,021	40%
Onshore Natural Gas Processing Facilities	100,000	50,211,548	566	21,581,714	17,459,840	39,041,555	78%	125	22%
	25,000	50,211,548	566	26,006,801	21,493,174	47,499,976	95%	287	51%
	10,000	50,211,548	566	27,113,211	21,094,641	49,207,852	98%	394	70%
	1,000	50,211,548	566	28,038,416	22,173,132	50,211,548	100%	566	100%
Onshore Natural Gas Transmission Facilities	100,000	73,198,355	1,944	1,589,418	11,833,992	30,200,243	41%	216	11%
	25,000	73,198,355	1,944	4,749,993	36,032,206	63,835,288	87%	874	45%
	10,000	73,198,355	1,944	5,480,135	41,670,038	71,359,167	97%	1,311	67%
	1,000	73,198,355	1,944	5,682,533	43,163,746	73,177,039	100%	1,659	85%
Underground Natural Gas Storage Facilities	100,000	11,719,044	398	3,262,598	2,003,351	5,265,948	45%	35	9%
	25,000	11,719,044	398	6,120,836	3,758,410	9,879,247	84%	131	33%
	10,000	11,719,044	398	6,800,178	4,175,550	10,975,728	94%	197	49%
	1,000	11,719,044	398	7,250,309	4,451,947	11,702,256	100%	346	87%
LNG Storage Facilities	100,000	1,956,435	157	469,981	167,496	637,477	33%	3	2%
	25,000	1,956,435	157	1,338,416	332,011	1,670,427	85%	29	18%
	10,000	1,956,435	157	1,504,228	356,085	1,860,314	95%	39	25%
	1,000	1,956,435	157	1,549,469	390,734	1,940,203	99%	54	34%
LNG Import Facilities	100,000	1,896,626	5	813,899	1,081,254	1,895,153	99.9%	4	80%
	25,000	1,896,626	5	813,899	1,081,254	1,895,153	99.9%	4	80%
	10,000	1,896,626	5	813,899	1,081,254	1,895,153	99.9%	4	80%
	1,000	1,896,626	5	814,531	1,082,095	1,896,626	100%	5	100%

Note: Totals may not add exactly due to rounding.

(C) Monitoring Method Options

(1) Review of Existing Relevant Reporting Programs/ Methodologies

To determine applicability of the different monitoring methods available, existing programs and guidance documents were reviewed. Six reporting programs and six guidance documents were reviewed. All of the program and guidance documents provide direction on estimating CH_4 and/ or CO_2 emissions, except the Western Regional Air Partnership, which deals exclusively with Volatile Organic Compound (VOC) emissions. All documents in general provide emissions rate (emissions factors) that can be used to estimate emissions and in some cases refer to continuous emissions monitoring. Table 2 provides a summary of the programs and guidance documents reviewed.

(2) Potential Monitoring Instruments

Depending on the particular source to be monitored in a facility, several of the currently available monitoring methods for estimating emissions could be used.

(a) Fugitive Emissions Detection

Traditional technologies like Toxic Vapor Analyzer (TVA) and Organic Vapor Analyzer (OVA) are appropriate for use in small facilities with few pieces of equipment. However, comprehensive leak detection in large facilities can be cumbersome, time consuming, and in many cases costly. But new infrared remote fugitive emissions detection technologies have emerged and are currently being used in the United States and internationally to very efficiently detect leaks across large facilities. Considering these factors, one of the following three technologies can be used to detect leaks in facilities depending on suitability;

§ **Infrared Remote Fugitive Emissions Detectors -** Hydrocarbons in natural gas emissions absorb infrared light. The infrared remote fugitive emissions detectors use this property to detect leakages in systems. There are two main types of detectors; a) those that scan the an area to produce images of fugitive emissions from a source, and b) those that point or aim an IR beam towards a potential source to indicate presence of fugitive emissions.

An IR camera scans a given area and converts it into a moving image of the area while distinctly identifying the location where infrared has been absorbed, i.e. the fugitive emissions source. The camera can actually “see” fugitive emissions. The advantages of IR cameras are that they are easy to use, very efficient in that they can detect multiple leaks at the same time, and can be used to do a comprehensive survey of a facility. The main disadvantage of an IR camera is that it is involves substantial capital investment depending on the features that are made available. Therefore, these cameras are most applicable in facilities with large number of equipment and multiple potential leak sources or when purchased at the corporate level, and then shared among the facilities, thereby lowering costs.

Aiming devices are based on infrared laser reflection, which are tuned to detect the interaction of CH_4 and other organic compounds with infrared light in a wavelength range where CH_4 has strong absorption bands but do not visually display an image of the fugitive emissions. Such devices do not have screens to view the fugitive emissions, but pin point the location of the emissions with a visual guide (such as a visible pointer laser) combined with an audible alarm when CH_4 is detected. These devices are considerably less expensive than the camera and also can detect fugitive emissions from a distance (i.e. the instrument need not be in close proximity to the emissions). But they take more time for screening, since each equipment (or component) has to be pointed at to determine if it is leaking. Also, if there are multiple leaks in the pathway of the IR beam then it may not accurately detect the right source of emissions.

§ **Toxic Vapor Analyzer (or Organic Vapor Analyzer) –** TVAs and OVAs consist of a flame ionization detector that is used to detect the presence of hydrocarbon and measure the concentration of the fugitive emissions. It consists of a probe that is moved close to and around the potential emissions source and an emissions detection results in a positive reading on the instrument monitoring scale. The concentration can be used in conjunction with correlation equations to determine the leak rate. However, such emissions estimates are unreliable and therefore TVAs and OVAs could be used where required for screening purposes only. The advantage of these instruments is that they have lower costs than IR cameras and several facilities conducting Leak Detection and Repair (LDAR) programs might already have these instruments, thereby reducing capital investment burden. But these instruments screen very slowly given that each potential emissions source has to be individually and thoroughly circumscribed less than 1 centimeter from the potentially leaking joints or seals.

(b) **Fugitive Emissions Measurement**

Three types of technologies can be used where appropriate to measure or quantify the magnitude of fugitive emissions once they have been detected.

§ **High Volume Sampler –** A high volume sampler consists of a simple fixed rate induced flow sampling system to capture the fugitive emissions and measure its volume. The fugitive emissions and the air surrounding the emissions source is drawn into the instrument using a sampling hose. The instrument measures the flow rate of the captured volume of air and emissions mixture. A separate sample of the ambient air is taken by the instrument to correct for the volume of ambient air that is captured along with the emissions.

§ **Meters –** Several types of meters measure natural gas flows and can be used for measurement of fugitive emissions from sources where the volume of emissions are large like in vent stacks.

Rotameter – A rotameter consists of a tapered calibrated transparent tube and a floating bob inside to measure emissions. To measure fugitive emissions a rotameter is placed over an emissions source (typically vents and open ended lines) and the emissions pass through the tube. As the emissions move through the tube it raises the floating bob to indicate the magnitude of emissions on the calibrated scale. Rotameters are most advantageous to use in cases where the emissions are very large. The disadvantage though is that it can only be used on leaks where the entire emissions can be captured and directed through the rotameter.

Turbine Meter –To measure fugitive emissions a turbine meter is placed over an emissions source and the emissions pass through the tube. As the emissions move through the tube it spins the turbine; the rate at which the turbine spins indicates the magnitude of emissions. Like rotameters, turbine meters are most advantageous to use in cases where emissions are very large. The disadvantage is that it can only be used on fugitive emissions that can be entirely captured and directed through the meter.

Hotwire Anemometer – Hotwire anemometers measure fugitive emissions velocity by noting the heat convected away by the emissions. The core of the anemometer is an exposed hot wire either heated up by a constant current or maintained at a constant temperature. In either case, the heat lost to emissions by convection is a function of the emissions velocity. Hotwire anemometers are best for measuring vents and open ended lines of known cross-sectional area and do not require complete capture of emissions. Hot wire anemometers have low levels of accuracy since they measure velocity that is converted into mass emissions rate.

Pitot Tube Flow Meter – A simple pitot tube is a right angled tube open at one end and closed at the other. The closed end is connected to a transducer to measure pressure of the inflowing emissions. The open end is aligned parallel to the direction of emissions flow. Fugitive emissions are directed into the tube so that the pressure required to bring the air inside the tube to stagnation is measured. The difference in pressure between the interior of the pitot tube and the surrounding air is measured and converted to an emissions rate. Pitot tube flow meters can be used when the cross-sectional area of an emitting vent or open ended line is known, or when the entire emission can be directed into the tube. The pitot tube flow meter measures pressure differential that is converted to mass emissions rate.

§ **Calibrated Bagging –** A calibrated bag made of anti-static material is used to enclose a fugitive emissions source to completely capture all the leaking gas. The time required to fill the bag with emissions is measured using a stop watch. The volume of the bag and time required to fill it is used to determine the mass rate of emissions. Calibrated bags have a very high accuracy, since all the emissions are captured in the measurement.

All of the fugitive emissions measurement instruments discussed above measure the flow rate of the natural gas emissions. In order to convert the natural gas emissions into CO_2 and CH_4 emissions, speciation factors determined from natural gas composition analysis must be applied. Another key issue is that all measurement technologies discussed require physical access to the emissions source in order to quantify emissions.

(c) **Engineering Estimation**

Several emissions sources do not require physical measurement of the emissions using a measurement instrument. For example, fugitive emissions to the atmosphere due to emergency conditions from vessels or other equipment and engineered emissions from equipment like pneumatic devices can be estimated or quantified using engineering calculations. This is referred to as engineering estimation.

(3) Potential Monitoring Methods

Using the potential monitoring instruments discussed in the previous section, monitoring methods can be of two types; Direct Measurement or Engineering Estimation. In direct measurement the fugitive emissions detection and measurement can be used. For engineering estimation, no detection is required, but the fugitive emissions can be estimated using engineering methods. Table 5 provides potential monitoring methods and emissions quantification methods. This section also discusses the use of Method 21 and emission factor approaches to estimate emissions.

Table 5: Source Specific Monitoring Methods and Emissions Quantification

Emission Source	Monitoring Method Type	Emissions Quantification Methods
Acid Gas Removal Vent Stacks	Engineering estimation	Simulation software
Blowdown Vent Stacks	Engineering estimation	Gas law and temperature, pressure, and volume between isolation valves
Centrifugal Compressor Dry Seals	Direct measurement	1) High volume sampler 2) Calibrated bag 3) Meter
Centrifugal Compressor Wet Seals	Direct measurement	1) High volume sampler 2) Calibrated bag 3) Meter
Compressor Fugitive Emissions	Direct measurement	1) High volume sampler 2) Calibrated bag 3) Meter
Dehydrator Vent Stacks	Engineering estimation	Simulation software
Flare Stacks	Engineering estimation and direct measurement	Velocity meter and mass/volume equations
Natural Gas Driven Pneumatic Pumps	1) Engineering estimation 2) or direct measurement	1) Manufacturer data, equipment counts, and amount of chemical pumped 2) Calibrated bag
Natural Gas Driven Pneumatic Manual Valve Actuator Devices	1) Engineering estimation 2) or direct measurement	1) Manufacturer data and actuation logs 2) Calibrated bag
Natural Gas Driven Pneumatic Valve Bleed Devices	1) Engineering estimation 2) or direct measurement	1) Manufacturer data and equipment counts 2) High volume sampler

		3) Calibrated bag 4) Meter
Non-pneumatic Pumps	Direct measurement	High volume sampler
Offshore Platform Pipeline Fugitive Emissions	Direct measurement	High volume sampler
Open-ended Lines (OELs)	Direct measurement	1) High volume sampler 2) Calibrated bag 3) Meter
Pump Seals	Direct measurement	1) High volume sampler 2) Calibrated bag 3) Meter
Facility Fugitive Emissions[1]	Direct measurement	High volume sampler
Reciprocating Compressor Rod Packing	Direct measurement	1) High volume sampler 2) Calibrated bag 3) Meter
Storage Tanks	1) Engineering estimation and direct measurement 2) or engineering estimation	1) Meter 2) Simulation software 3) Vasquez-Beggs Equation

The specific details on methods of monitoring for each approach is as follows.

(a) Direct Measurement

1. Detection

Infrared Remote Fugitive Emissions Detection

<u>Method</u>

Infrared remote (IR) fugitive emissions detection instruments can identify specific emissions sources as emitting. Such instruments have the capability to trace a fugitive emission back to the specific point where it escapes the process and enters the atmosphere. There are several IR technology instruments that can detect the presence of a plume of emissions from a facility or general operational area.

For IR instruments that visually display an image of fugitive emissions, the background of the emissions has to be appropriate for emissions to be detectable. Therefore, the operator should inspect the emissions source from multiple angles or locations until the entire source has been viewed without visual obstructions to identify all emissions.

Other IR detection instruments, such as those based on IR laser reflection, are tuned to detect the interaction of methane and other organic compounds with infrared light in a wavelength range where methane has strong absorption bands. However, they do not visually display an image of the fugitive emissions. Such instruments will have to monitor potential emissions sources along all joints and connection points where a potential path to the atmosphere exists. For example, a flange can potentially have fugitive emissions along its circumference and such surfaces will have to be monitored completely by tracing the instrument along each surface.

Calibration

The minimum detectable quantity of fugitive emissions depends on a number of factors including manufacturer, viewing distance, wind speed, gas composition, ambient temperature, gas temperature, and type of background behind the fugitive emissions. For best survey results, fugitive emissions detection can be performed under favorable conditions, such as during daylight hours, in the absence of precipitation, in the absence of high wind, and, for active laser devices, in front of appropriate reflective backgrounds within the detection range of the instrument. Fugitive emissions detection and measurement instrument manuals can be used to determine optimal operating conditions to help ensure best results.

OVAs and TVAs

Method

TVAs and OVAs can be used for all fugitive emissions detection that is safely accessible at close-range. For each potential emissions source, all joints, connections, and other potential paths to the atmosphere would be monitored for emissions. Due to residence time of a sample in the probe, there is a lag between when an emission is captured and the operator is alerted. To pinpoint the source of the fugitive emission, upon alert the instrument can be slowly retraced over the source until the exact location is found.

Calibration

Method 21 guidance can be used to calibrate the TVA or OVA using guidelines from *Determination of Volatile Organic Compound Leaks* Sections 3, 6, and 7.

2. Measurement

High Volume Sampler

High volume samplers are moderate cost and have a maximum capacity adequate to measure up to 30 leaking components per hour with high precision at 0.02 percent methane. This allows for reduced labor costs and survey times while maintaining precise results. For this reason, high volume samplers are considered the preferred and likely most cost-effective measurement option for emissions within their maximum range. However, large component emissions and many vent emissions are above the high volume sampler capacity and therefore warrant the use of other measurement instruments.

Method

A high volume sampler is typically used to measure only cold and steady emissions for which the instrument can intake the entire emission from a single source. To ensure proper use of the instrument, a trained technician can conduct the measurements. The technician will have to be conversant with all operating procedures and measurement methodologies relevant to using a high volume sampler, such as positioning the instrument for complete capture of the fugitive emissions without creating backpressure on the source. If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then anti-static wraps or other aids can to be used to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual. The attachments help capture the emissions from different points on the source allowing the measurement of the emission by the high volume sampler.

To estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions, the following calculations can be used:

►Volumetric Fugitive Emissions

Volumetric CH_4 and CO_2 fugitive emissions from natural gas emissions can be calculated using the following equation:

$$E_{s,i} = E_{s,n} * M_i \qquad \textbf{Equation 1}$$

where,

$E_{s,i}$ = GHG *i* (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions

$E_{s,n}$ = natural gas volumetric fugitive emissions at standard conditions

M_i = mole percent of a particular GHG *i* in the natural gas applicable to each source category as follows;

- Facility specific GHG mole percent in produced natural gas for offshore petroleum and natural gas production facilities.
- Facility specific GHG mole percent in feed natural gas for all fugitive emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all fugitive emissions sources downstream of the de-methanizer for onshore natural gas processing facilities.
- Facility specific GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.
- Facility specific GHG mole percent in natural gas stored in underground natural gas storage facilities.
- Facility specific GHG mole percent in natural gas stored in LNG storage facilities.
- Facility specific GHG mole percent in natural gas stored in LNG import facilities.
- Each facility for all of the source categories shall use an annual average GHG mole percent in natural gas in estimating GHG fugitive emissions.

►Mass Fugitive Emissions

Mass GHG fugitive emissions at standard conditions can be calculated using the following equation:

$$Mass_{s,i} = E_{s,i} * r_i \qquad \textbf{Equation 2}$$

where,

$Mass_{s,i}$ = GHG *i* (either CH_4 or CO_2) mass fugitive emissions at standard conditions

$E_{s,i}$ = GHG *i* (either CH_4 or CO_2) volumetric fugitive emissions at standard conditions

r_i = density of GHG i; 1.87 kg/m^3 for CO_2 and 0.68 kg/m^3 for CH_4

Calibration

The instrument can be calibrated at 2.5% and 100% CH_4 by using calibrated gas samples and by following the manufacturer's instructions for calibration.

Calibrated Bags

Calibrated bags are the lowest cost measurement technique, can measure up to 30 leaking components in an hour, but may require two operators (one to deploy the bag, the other to measure time inflation). It is a suitable technique for emission sources that are within a safe temperature range and can be safely accessed. The speed of measurement is highly dependent on the fugitive emissions rate and the results are susceptible to human error in enclosing the emission source and taking the measurement data, leading to lower precision and accuracy. For those sources outside the capacity of high volume samplers and within the limitations of bagging, this would be a second best choice for quantification.

Method

Calibrated bags (also known as vent bags) can be used only where the emissions are at near-atmospheric pressures and the entire fugitive emissions volume can be captured for measurement. Using these bags on high pressure vent stacks can be dangerous.

For conducting measurement the bag is physically held in place by a trained technician, enclosing the emissions source, to capture the entire emissions and record the time required to completely fill the bag. Three measurements of the time required to fill the bag can be conducted to estimate the emissions rates. The average of the three rates will provide a more accurate measurement than a single measurement.

Ambient temperature and pressure of natural gas fugitive emissions can be converted to standard temperature and pressure natural gas fugitive emissions using the following equation;

$$E_{s,n} = \frac{E_{a,n} * (460 + T_s) * P_a}{(460 + T_a) * P_s} \qquad \textbf{Equation 3}$$

where,

$E_{s,n}$ = natural gas volumetric fugitive emissions at standard temperature and pressure (STP) conditions

$E_{a,n}$ = natural gas volumetric fugitive emissions at actual conditions

T_s = Temperature at standard conditions (^oF)

T_a = Temperature at actual emission conditions (^oF)

P_s = Absolute pressure at standard conditions (inches of Hg)

P_a = Absolute pressure at ambient conditions (inches of Hg)

Both CH_4 and CO_2 volumetric and mass fugitive emissions can be calculated from volumetric natural gas fugitive emissions using the Equations 1 and 2.

Calibration

To ensure accurate results, a technician can be trained to obtain consistent results when measuring the time it takes to fill the bag with fugitive emissions.

Metering

Meters vary in cost and precision, but can be advantageous for measuring large fugitive emissions rates exceeding high volume sampler range, unsafe for calibrated bagging as well as non-continuous fugitive emissions rates. Total emissions measurement devices such as rotameters can be as accurate as high volume samplers and calibrated bagging. Applicability is limited to large fugitive emissions rates and the presence of an appropriately sized conduit to direct all emissions through the meter. Velocity measurement devices such as pitot tubes and hot wire anemometers used in conjunction with engineering calculations are much less accurate but may be the only method safe for very hot, very cold, or difficult to safely access the emissions flow.

Method

To ensure accurate measurements when using metering (e.g. rotameters, turbine meters, and others), all emissions from a single source will have to be channeled directly through the meter. An appropriately sized meter can be used to prevent the flow from exceeding the full range of the meter and conversely to have sufficient momentum for the meter to register continuously in the course of measurement. Ambient temperature and pressure of natural gas fugitive emissions can be converted to standard temperature and pressure natural gas fugitive emissions using Equation 3. Equations 1 and 2 can be used to estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions.

Calibration

The meters can be calibrated using either one of the two methods provided below:

- Develop calibration curves by following the manufacturer's instruction.
- Weigh the amount of gas that flows through the meter into or out of a container during the calibration procedure using a master weigh scale (approved by National Institute of Standards and Technology (NIST) or calibrated using standards traceable by NIST) that has a very high degree of accuracy. Determine correction factors for the flow meter according to the manufacturer's instructions, record deviations from the correct reading at several flow rates, plot the data points, compare the flowmeter output to the actual flowrate as determined by the master weigh scale and use the difference as a correction factor.

(b) Engineering Estimation

For several sources, direct measurement is not safe, cost-effective, or possible. These sources are outlined below along with relevant engineering estimation methods that can be used to estimate fugitive GHG gas emissions from each source.

Acid Gas Removal Vent Stacks

Operators can calculate fugitive emissions from acid gas removal vent stacks using simulation software packages, such as ASPEN™ or AMINECalc™. Different software packages might use different calculations and input parameters to determine emissions from an acid gas removal units. However, there are some parameters that directly impact the accuracy of emissions calculation. Therefore, any standard simulation software could be used assuming it accounts for the following operational parameters:

- Natural gas feed temperature, pressure, and flow rate;
- Acid gas content of feed natural gas;
- Acid gas content of outlet natural gas;
- Unit operating hours, excluding downtime for maintenance or standby;
- Fugitive emissions control method(s), if any, and associated reduction of fugitive emissions;
- Exit temperature of natural gas; and
- Solvent pressure, temperature, circulation rate, and weight.

Natural Gas Driven Pneumatic Pumps

Fugitive emissions from natural gas driven pneumatic pumps can be calculated using data obtained from the manufacturer for natural gas emissions per unit volume of liquid pumped. Operators can maintain a log of the amount of liquid pumped annually for individual pneumatic pumps and use the following equation for calculating fugitive emissions:

$$E_{s,n} = F_s * V \qquad \textbf{Equation 4}$$

where,

$E_{s,n}$ = natural gas fugitive emissions at standard conditions

F_s = natural gas driven pneumatic pump gas emissions in "emissions per volume of liquid pumped" units at standard conditions, as provided by the manufacturer

V = Volume of liquid pumped annually

Both CH_4 and CO_2 volumetric and mass fugitive emissions can be calculated from volumetric natural gas fugitive emissions using the Equations 1 and 2.

As an alternative to manufacturer data on pneumatic pump natural gas emissions, the operator can conduct a one-time measurement to determine natural gas emissions per unit volume of liquid pumped using a calibrated bag for each pneumatic pump, when it is pumping liquids. This measurement can be converted to emissions at standard conditions using Equation 3 and then substituted into the equation above for F_s to calculate GHG fugitive emissions.

Natural Gas Driven Pneumatic Manual Valve Actuators

Fugitive emissions from natural gas driven pneumatic manual valve actuators can be calculated using data obtained from the manufacturer for natural gas emissions per actuation. Operators can maintain a log of the number of manual actuations annually for individual pneumatic devices and use the following equation:

$$E_{s,n} = A_s * N$$ **Equation 5**

where,

$E_{s,n}$ = natural gas fugitive emissions at standard conditions

A_s = natural gas driven pneumatic valve actuator natural gas emissions in "emissions per actuation" units at standard conditions, as provided by the manufacturer.

N = Number of times the pneumatic device was actuated through the reporting period

Both CH_4 and CO_2 volumetric and mass fugitive emissions can be calculated from volumetric natural gas fugitive emissions using Equations 1 and 2.

As an alternative to manufacturer data, the operator could conduct a one-time measurement to determine natural gas emissions per actuation using a calibrated bag for each pneumatic device. This measurement can be converted to emissions at standard conditions using Equation 3 and then substituted for A_s in the equation above to calculate GHG emissions.

Natural Gas Driven Pneumatic Bleed Devices

Fugitive emissions from natural gas driven pneumatic valve bleed devices can be calculated using manufacturer data for the gas bleed rate of specific models during normal operations using the following equation:

$$E_{s,n} = B_s * T$$ **Equation 6**

where,

$E_{s,n}$ = natural gas fugitive emissions at standard conditions

B_s = natural gas driven pneumatic device bleed rate in "emissions per unit time" units at standard conditions, as provided by the manufacturer

T = amount of time the pneumatic device has been operational through the reporting period

Both CH_4 and CO_2 volumetric and mass fugitive emissions can be calculated from volumetric natural gas fugitive emissions using Equations 1 and 2.

As an alternative to manufacturer data, the operator could conduct a one-time measurement to determine natural gas bleed rate using a high volume sampler or calibrated bag or meter for each pneumatic device. This measurement can be converted to emissions at standard conditions using Equation 3 and then substituted for B_s in the equation above to calculate GHG emissions.

Blowdown Vent Stacks

Fugitive emissions from blowdown vent stacks can be calculated using the total volume between isolation valves (including all natural gas-containing pipelines and vessels) and logs of the number of blowdowns for each piece of equipment using the following equation:

$$E_{a,n} = N * V_v \qquad \textbf{Equation 7}$$

where,

$E_{a,n}$ = natural gas fugitive emissions from blowdowns

N = number of blowdowns for the equipment in given year

V_v = total volume of blowdown equipment chambers (including, but not limited to, pipelines and vessels) between isolation valves

Ambient temperature and pressure of natural gas fugitive emissions can be converted to standard temperature and pressure natural gas fugitive emissions using Equation 3. Equations 1 and 2 can be used to estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions.

Dehydrator Vent Stacks

Fugitive emissions from a dehydrator vent stack can be calculated using a simulation software package, such as GLYCalc™. Different software packages might use different calculations and input parameters to determine emissions from dehydration systems. However, there are some parameters that directly impact the accuracy of emissions calculation. Therefore, any standard simulation software could be used provided it accounts for the following operational parameters:

- Feed natural gas flow rate;
- Feed natural gas water content;
- Outlet natural gas water content;
- Absorbent circulation pump type(natural gas pneumatic/ air pneumatic/ electric);
- Absorbent circulation rate;
- Absorbent type: including, but not limited to, triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG);
- Use of stripping natural gas;
- Use of flash tank separator (and disposition of recovered gas);
- Hours operated; and
- Wet natural gas temperature, pressure, and composition.

(c) Combination of Direct Measurement and Engineering Estimation

Flare Stacks

In the cases of flare stacks, an engineering estimation of fugitive emissions requires data that typically is not available, i.e. the volume of natural gas sent to the flare system. For this reason a measurement of the volume of natural gas flared will be necessary. But it is not a direct measurement of the fugitive emissions. Thus, a combination of measurement and engineering estimation can be used with the following equation:

$$E_{a,i} = V_a \times (1-h) \times X_i \quad + \ (1-K)*h*V_a*Y_j*R_{j,i} \qquad \textbf{Equation 8}$$

Where,

$E_{a,i}$ = annual fugitive emissions from flare stack

V_a = Volume of natural gas sent to flare stack

η = percent of natural gas combusted by flare (default is 95% for non-steam aspirated flares and 98% for steam aspirated of air injected flares)

X_i = concentration of GHG *i* in the flare gas

Y_j = concentration of natural gas hydrocarbon constituents *j* (such as methane, ethane, propane, butane, and pentanes plus)

$R_{j,i}$ = number of carbon atoms in the natural gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus)

K = “1” when GHG *i* is methane and “0” when GHG *i* is CO_2

V_A and X_i from flare stacks can be estimated using the following procedure:

- A flow velocity measuring device (such as hot wire anemometer or pitot tube) can be inserted directly upstream of the flare stack to determine the velocity of natural gas sent to flare.
- Actual temperature and pressure conditions of the natural gas sent to flare can be recorded.
- A sample representative natural gas to the flare stack can be taken every quarter to evaluate the composition of GHGs present in the stream. The average of the most recent four natural gas composition analyses conducted using ASTM D1945-03 can be recorded.

Ambient temperature and pressure of GHG fugitive emissions can be converted to standard temperature and pressure GHG fugitive emissions using the following equation;

$$E_{s,i} = \frac{E_{a,i}*(460+T_s)*P_a}{(460+T_a)*P_s} \qquad \textbf{Equation 9}$$

where,

$E_{s,i}$ = GHG *i* volumetric fugitive emissions at standard temperature and pressure (STP) conditions
$E_{a,n}$ = natural gas volumetric fugitive emissions at actual conditions
T_s = Temperature at standard conditions (^oF)
T_a = Temperature at actual emission conditions (^oF)
P_s = Absolute pressure at standard conditions (inches of Hg)
P_a = Absolute pressure at ambient conditions (inches of Hg)

Mass GHG fugitive emissions at standard conditions can be calculated using Equation 2.

Centrifugal Compressor Wet Seal Degassing Vents

In several compressors, the wet seal degassing vents emit flash gas from degassed oil straight into or close to the compressor engine exhaust vent stack. The temperatures at the degassing vent exit are very high due to the proximity to the engine exhaust vent stack. In such cases, emissions can be estimated using the following procedure:

- A flow velocity measuring device (such as hot wire anemometer or pitot tube) can be inserted directly upstream of the degassing unit vent exit to determine the velocity of gas sent to the vent. Then volume of natural gas sent to vent can be calculated from the velocity measurement.
- Actual temperature and pressure conditions of the gas sent to degassing vent can be recorded.
- A sample representative of the gas to the degassing vent can be taken every quarter to evaluate the composition of GHGs present in the stream. The average of the most recent four natural gas composition analyses conducted using ASTM D1945-03 can be recorded.
- Ambient temperature and pressure of natural gas fugitive emissions can be converted to standard temperature and pressure natural gas fugitive emissions using Equation 3. Equations 1 and 2 can be used to estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions.

Storage Tanks

In the case of storage tanks, emissions rates are not constant; and thus, a one-time measurement may not provide accurate emissions rates for the entire reporting period. To accurately estimate emissions from storage tanks, it is necessary to conduct a one-time measurement during a cycle of operation that is representative of the tank operations through the year. The following equation can be used to calculate GHG emissions:

$$E_{a,h} = Q \times ER \qquad \textbf{Equation 10}$$

where,

$E_{a,h}$ = hydrocarbon vapor fugitive emissions at actual conditions

Q = storage tank total annual throughput

ER = measured hydrocarbon vapor emissions rate per throughput (e.g. cubic feet/barrel)

ER can be estimating using the following procedure:

- The hydrocarbon vapor emissions from storage tanks can be measured using a flow meter for a test period that is representative of the normal operating conditions of the storage tank throughout the year and which includes a complete cycle of accumulation of hydrocarbon liquids and pumping out of hydrocarbon liquids from the storage tank.
- The throughput of the storage tank during the test period can be recorded.
- The temperature and pressure of hydrocarbon vapors emitted during the test period can be recorded.
- A sample of hydrocarbon vapors can be collected for composition analysis.

Ambient temperature and pressure of natural gas fugitive emissions can be converted to standard temperature and pressure natural gas fugitive emissions using Equation 3. Equations 1 and 2 can be used to estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions.

If this combination of direct measurement and engineering estimation is not feasible, a second method is to use simulation software such as API TankCalc to estimate fugitive emissions from storage tanks. Therefore, any standard simulation software could be used assuming it accounts for the following operational parameters:

- Feed liquid flow rate to tank;
- Feed liquid API gravity;
- Feed liquid composition or characteristics;
- Upstream (typically a separator) pressure;
- Upstream (typically a separator) temperature;
- Tank or ambient pressure; and
- Tank or ambient temperature;

A third method for storage tank fugitive emissions quantification is use of the Vasquez-Beggs equation. This correlation equation provides an estimate of the gas-to-oil ratio for flashing tank vapors; however, it does not provide the GHG of the vapors, so composition analysis of tank vapors is still required. Equation 11 demonstrates the use of this correlation equation:

$$GOR = A \times G_{flashgas} \times \left(P_{sep} + 14.7\right) \times \exp\left(\frac{C \times G_{oil}}{T_{sep} + 460}\right) \qquad \textbf{Equation 11}$$

where,
GOR = ratio of flash gas production to standard stock tank barrels of oil produced, in standard cubic feet/barrel (barrels corrected to 60°F)
$G_{flash\ gas}$ = Specific gravity of the tank flash gas, where air = 1. A suggested default value for $G_{flash\ gas}$ is 1.22
G_{oil} = API gravity of stock tank oil at 60°F

P_{sep} = Pressure in separator (or other vessel directly upstream), in pounds per square inch gauge
T_{sep} = Temperature in separator (or other vessel directly upstream of the tank), °F
A = 0.0362 for G_{oil} </= 30°API, or 0.0178 for G_{oil} > 30°API
B = 1.0937 for G_{oil} </= 30°API, or 1.187 for G_{oil} > 30°API
C = 25.724 for G_{oil} </= 30°API, or 23.931 for G_{oil} > 30°API

(d) Method 21

This is the authorized method for detecting and quantifying fugitive[3] volatile organic carbon (VOC) emissions under 40 CFR Part 60 VOC monitoring and control. The method specifies the performance of emissions detection instruments such that it is equivalent to an OVA with a probe not exceeding one fourth inch outside diameter, used to slowly circumscribe the entire component interface where fugitive emissions could occur. The probe must be maintained in close proximity to the interface unless it could be damaged by rotating shafts or plugged with ingested lubricants or greases, in which case it can be no more than 1 centimeter away from the leak interface. Method 21 specifies a "leak/no-leak" threshold definition, which this proposed rule is not adopting. Method 21 also allows certain alternative fugitive emissions detection methods, such as soap solutions (where the fugitive emissions source is below the boiling point and above the freezing point of the soap solution). Method 21 does not specify any emissions mass or volumetric quantification methods; only a concentration definition of emissions expressed in parts per million concentration of combustible hydrocarbon in the air stream of the instrument probe. Quantification is generally done using EPA published quantification guidelines which are statistically determined for a very large population of similar components, but not very accurate for single leaks or small populations. Therefore, Method 21 is not considered to be appropriate for measurement purposes for the proposed rule. Method 21 was recently amended with performance standards for remote leak sensing devices, such as those based on infrared (IR) light imaging or laser beams in a narrow wavelength absorbed by hydrocarbon gases.

(e) Activity Factor and Emissions Factor for All Sources

Emissions factors for all the sources discussed are available in a study conducted in 1992 and published in 1996 by the Gas Research Institute (GRI) and U.S. EPA[4]. There have been no subsequent comparable studies published to replace or revise the estimates available from this study. However, the industry operations have changed significantly with the introduction of new technologies and improved industry operating/maintenance practices to mitigate emissions. These are not reflected in the emissions factors available from the EPA/GRI study. Also, in many cases the EPA study estimate of emissions factors are not representative of industry operations because the estimates were based on limited or no field data and hence not representative of the entire country. Therefore, this method for estimation of the emissions is not is not considered to be appropriate for a mandatory GHG reporting program.

[3] Again, in this TSD, "fugitive" refers to both intentional and unintentional leaks. Under Method 21, "fugitive" refers only to what would be considered unintentional leaks
[4] Gas Research Institute/ U.S. Environmental Protection Agency. June 1996. Methane Emissions from the Natural Gas Industry. GRI-94/0257.22, EPA-600/R-96-080e

(f) TVAs/ OVAs for Leak Measurement

As discussed above under Method 21, TVA and OVA instruments do not quantify the volumetric or mass emissions. They quantify the concentration of combustible hydrocarbon in the air stream induced through the maximum one fourth inch outside diameter probe. This small size probe rarely ingests all of the fugitive emissions from a component leak. Therefore, these instruments are used primarily for fugitive emissions detection. EPA provides emissions quantification guidelines derived from emissions detection data using OVA and TVA instruments. One choice of instrument emissions detection data is referred to as “leak/no-leak” where a component is determined to be leaking when the OVA instrument pegs at the Federal leak definition of 10,000 ppm, or the TVA reads a concentration of 10,000 ppm or higher. When the OVA or TVA reads a concentration less than 10,000 ppm, the component is determined to be “not leaking.” Hence, these quantification tables have a “no-leak” emission factor for all components found to have emissions rates below the leak definition, and “pegged” emission factors for all components above the leak definition. Alternatively, the “stratified” method has emission factors based on ranges of actual leak concentrations below, at and above the leak definition. OVA instruments normally peg at 10,000 ppm, and so are unsuitable for use with the “stratified” quantification factors. For the proposed rule, fugitive emissions detection by more cost-effective screening technologies in conjunction with direct measurement methodologies is deemed a better overall approach to emissions quantification than the labor intensive OVA/TVA and potential use of highly unreliable fugitive emission factors for these instruments.

(g) Mass Balance for Quantification. There are mass balance methods that could be considered to calculate emissions from a reporting program. This approach would take into account the volume of gas entering a facility and the amount exiting the facility, with the difference assumed to be emitted to the atmosphere. This is most often discussed for emissions estimation from the transportation segment of the industry. For transportation, the mass balance is often not recommended because of the uncertainties surrounding meter readings and the large volumes of throughput relative to fugitive emissions. Applicability to other segments of the petroleum and natural gas industry is uncertain at this time.

(4) Additional Questions Regarding Potential Monitoring Methods

There are several additional issues regarding the potential monitoring methods that are relevant to estimating fugitive emissions from the petroleum and natural gas industry.

(a) Source Level Fugitive Emissions Detection Threshold

This document does not indicate a particular fugitive emissions definition or detection threshold requiring emissions measurement. This is because different potential fugitive emissions detection instruments have different levels and types of detection capabilities, i.e. some instruments provide a visual image while others provide a digital value on a scale (not directly related to mass emissions). Hence the magnitude of actual emissions can only be determined after measurement. This, however, may not serve the purpose of a reporting rule in limiting burden on emissions reporting. A facility can have hundreds of small emissions (as low as 3 grams per hour) and it might not be practical to measure all such small emissions for reporting.

There are, however, two possible approaches to overcome this issue, as follows;

(i) Instrument Performance Standards

Performance standards can be provided for fugitive emissions detection instruments and usage such that all instruments follow a common minimum detection threshold. The Alternate Work Practice to Detect Leaks from Equipment standards for IR fugitive emissions detection instruments recently developed by EPA can potentially be proposed. In such a case all detected emissions from components subject to the proposed rule may require measurement and reporting.

The current Method 21 practice is based on a 25 year old technology that uses gas concentration measurement at the tip of a probe manually circumscribed on or within one centimeter along the entire potential emissions surface to detect fugitive emissions. The current threshold for a source to be identified as emitting is 10,000 parts per million by volume (ppmv) of VOC and 500 ppmv of Hazardous Air Pollutants (HAPs) at any point. In a study conducted by API at seven California refineries with over five years of measured data (11.5 million data points), it was found that over 90 percent of the controllable emissions (i.e. fugitive emissions that can be mitigated once detected) are contributed by about 0.13 percent of the components. In a typical Method 21 program the costs of conducing emissions detection remain the same during each recurring study period. This is because the determination of whether a potential source is emitting or not is made only after every potential source is screened for emissions as described above. Given the fact that only a small number of sources contribute to majority of the emissions, the detection of the remaining sources emitting at smaller mass rates is not imperative to the success of the program. This means that an alternative work practice/ technology that is more cost effective than the current gas concentration in air measurement technology and that can detect equal or greater amounts of controllable emissions is feasible for the Method 21 program.

The EPA Alternate Work Practice (AWP) promulgated the use of optical gas imaging technologies that can detect in some cases emissions as small as 1 gram per hour. The AWP requires technology effectiveness of emissions equal to 60 grams/hour, i.e. the technology should be able to routinely detect all emissions equal to or greater than 60 grams/hour. EPA determined by Monte Carlo simulation that 60 grams/hour emissions from valves are equivalent to the 10,000 ppmv definition of an actionable emissions source in Method 21. To implement the technology effectiveness, the AWP requires that the detection instrument meet a minimum detection sensitivity mass flow rate. Or, alternatively, the mass flow rate for the process being studied should be calculated by prorating a standard detection sensitivity emissions rate using equations provided by the AWP proposal. For the purposes of a mandatory reporting program, such a performance standard could be adapted for the detection of natural gas emissions with methane as the predominant component (it should be noted that Method 21 is specifically meant for VOCs and HAPs and not for methane).

(ii) Fugitive Emissions Definition

An emissions definition for detection using OVA/TVA can be provided. When using IR fugitive emissions detection instruments all potential sources that have emissions detected may require emissions quantification. Alternatively, the operator can be given a choice of first detecting emissions sources using the IR detection instrument and then verifying for measurement status using the emissions definition for an OVA/TVA.

(b) Duration of Fugitive Emissions

Some fugitive emissions by nature occur randomly within the facility. Therefore, there is no way of knowing when a particular source started emitting. The potential monitoring method requires a one time fugitive emissions detection and measurement. But the emissions detected and measured will have to be assumed to be emitting throughout the reporting year, unless no emissions detection was recorded at an earlier and/or later point in the reporting period. However, where this does not occur, emissions reported could be higher than actual.

(c) Unofficial Surveys

Natural gas is a saleable commodity and rising natural gas prices are providing an economic incentive to reduce emissions. The petroleum and natural industry is already selectively implementing voluntary fugitive emissions detection and repair programs. Such voluntary programs are desired, but can pose an accounting problem with respect to emissions reporting for a mandatory GHG reporting program. The potential monitoring method does not preclude any program from detecting and repairing fugitive emissions just prior to the official detection, measurement, and reporting of emissions in which case the repaired emissions may not get reported. In developing a reporting program, one would have to decide whether such a scenario could lead to a misrepresentation of emissions estimates, or whether this would be an acceptable outcome.

(d) Fugitive Emissions at Different Operational Modes

If a reporting program relies on a one time or periodic measurement the measured emissions may not account for the different modes in which a particular technology operates throughout the reporting period. This may be particularly true for measurements taken at compressors. Fugitive emissions from a compressor are a function of the mode in which the compressor is operating: i.e. offline pressurized, or offline de-pressurized. Typically, a compressor station consists of several compressors with one (or more) of them on standby based on system redundancy requirements and peak delivery capacity. When a compressor is taken offline it may be kept pressurized with natural gas or de-pressurized. When the compressor is offline and kept pressurized then fugitive emissions result from closed blowdown valves and reciprocating compressor rod packing leaks. When the compressor is offline and depressurized, then fugitive emissions result from releasing the natural gas to the atmosphere and from isolation valve leakage. When operating, compressor fugitive emissions result from compressor seals or rod packing and other components in the compressor system. In each of the compressor modes the resultant fugitive emissions are significantly different. One potential approach to address this issue is that operators measure emissions for each mode the compressor is operated in and the period of time during the reporting period at which the compressor is in the different modes to account for the varying levels of fugitive emissions. However, this will increase the reporting burden, since measurements will have to be taken at each mode of compressor operation. The time that the equipment is in various operational modes would also have to be tracked.

(e) Natural Gas Composition

When measuring fugitive emissions using the various measurement instruments (high volume sampler, calibrated bags, and meters measure natural gas emissions), only flow rate is measured and the individual CH_4 and CO_2 emissions are estimated from the natural gas mass emissions using natural gas composition appropriate for each facility. For this purpose, the monitoring methodologies discussed above would require that facilities use existing gas composition estimates to determine CH_4 and CO_2 components of the natural gas emissions (flare stack and storage tank fugitive emissions are an exception to this general rule). These gas composition estimates are assumed to be available with facilities. But this may or may not be a practical assumption. In the absence of gas composition, periodic measurement of the required gas composition for speciation of the natural gas mass emissions into CH_4 and CO_2 mass emissions could be a potential option.

(f) Physical Access for Leak Measurement

All emissions measurement techniques require physical access to the leaking source. The introduction of remote leak detection technologies based on infrared (IR) light absorption by hydrocarbon gas clouds from atmospheric leaks makes leak detection quicker and possible for sources outside of arms reach from the ground or fixed platforms. The class of unintentional leaking components, e.g. flanges, valve stems, equipment covers, is generally smaller than the class of fugitives from vent stacks, whether designed, intentional emissions or through-leaking valves intended to isolate the process from a vent stack. The former class of component leaks is expensive to measure where they are not accessible within arms reach from the ground or a fixed platform. Vent stacks are often located out of access by operators for safety purposes, but may represent large emission sources. Where emissions are detected by remote sensing devices such as IR cameras, emissions measurement may be cost-effective using the following source access techniques:

§ Short length ladders positioned on the ground or a fixed platform where OSHA regulations do not require personnel enclosure and the measurement technique can be performed with one hand;
§ Bucket trucks can safely position an operator within a full surround basket allowing both hands to be used above the range of ladders or for measurement techniques requiring both hands;
§ Relatively flat, sturdy roofs of equipment buildings and some tanks allow safe access to roof vents that are not normally accessible from fixed platforms or bucket trucks;
§ Scaffolding is sometimes installed for operational or maintenance purposes that allow access to emission sources not normally accessible from the ground, fixed platforms and out of reach of bucket trucks.

(D) Procedures for Estimating Missing Data

It is possible that some companies would be missing data necessary to quantify annual emissions. In the event that data are missing, potential procedures to fill the data gap are outlined below and are organized by data type.

In general, although there is always the possibility to use a previous years' data point to replace missing data in the current reporting year, this is not ideal due to the impact that various operating conditions can have on fugitive emissions. Where using previous years' data are not desirable, then a reporting rule might require 100% data availability. In other words, there would be no missing data procedures provided. If any data were identified as missing, then there would be an opportunity to recollect the emissions data over the course of the current reporting period.

Emissions Measurement Data

Measured data can be collected by trained engineers using a high volume sampler, meter, or calibrated bag. Over the course of the data collection effort, some of the measured fugitive emissions rates could get lost temporarily or permanently due to human error, or storage errors such as lost hard-drives and records. If measured data is missing then the field measurement process should be repeated within the reporting period. If this proves to be impossible, then the previous reporting period's data could be used to estimate fugitive emissions from the current reporting period.

Engineering Estimation Data

Engineering estimations rely on the collection of input data to the simulation software or calculations. A potential procedure for missing input data is outlined below for each type of input parameter.

- Operations logs. If operating logs are lost or damaged for a current reporting period, previous reporting period's data could be used to estimate fugitive emissions. Again, using previous years' data are not as desirable as there could be significant differences from year to year based on operating conditions.
- Process conditions data. Estimating fugitive emissions from acid gas removal vent stacks, blowdown vent stacks, dehydrator vent stacks, natural gas driven pneumatic valve bleed devices, natural gas driven pneumatic pumps, and storage tanks requires data on the process conditions (e.g., process temperature, pressure, throughputs, vessel volumes). If, for any reason, these data are incomplete or not available for the current reporting period, field operators or engineers could recollect data wherever possible. If this data cannot be collected, then relevant parameters for estimation of emissions can be used from previous reporting period. However, where possible current reporting period parameters should be used for emissions estimation due to the reasons listed above.

Emissions Estimation Data for Storage Tanks and Flares

Fugitive emissions from storage tanks and flares might require a combination of both direct measurement and engineering estimation to quantify emissions. Storage tank emissions calculation requires the measurement of “fugitive emissions per throughput” data. If this data is missing then the previous year’s estimate of “fugitive emissions per throughput” measured data could be used with current period throughput of the storage tank to calculate emissions.

Calculating emissions from flares requires the volume of flare gas measured using a meter. If these data are missing then the flare gas in the current reporting period could be estimated by scaling the flare gas volume from previous reporting period by adjusting it for current period throughput of the facility.

(E) QA/QC Requirements

Equipment Maintenance

Equipment used for monitoring, both leak detection and measurement, should be calibrated on a scheduled basis in accordance with equipment manufacturer specifications and standards. Generally, such calibration is required prior to each monitoring cycle for each facility. A written record of procedures needed to maintain the monitoring equipment in proper operating condition and a schedule for those procedures could be part of the QA/QC plan for the facility.

An equipment maintenance plan could be developed as part of the QA/QC plan. Elements of a maintenance plan for equipment could include the following:

- Conduct regular maintenance of monitoring equipment.
    - Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures;
    - Keep a record of all testing, maintenance, or repair activities performed on any monitoring instrument in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring instrument and records of any corrective actions associated with a monitor’s outage period.

Data Management

Data management procedures could be included in the QA/QC Plan. Elements of the data management procedures plan are as follows:

- Check for temporal consistency in production data and emission estimate. If outliers exist, can they be explained by changes in the facility’s operations, etc.?
    - A monitoring error is probable if differences between annual data cannot be explained by:
        - Changes in activity levels,
        - Changes concerning monitoring methodology,
        - Changes concerning change in equipment,

- § Changes concerning the emitting process (e.g. energy efficiency improvements).[5]

- Determine the "reasonableness" of the emission estimate by comparing it to previous year's estimates and relative to national emission estimate for the industry:
  - o Comparison of emissions by specific sources with correction for throughput, if required,
  - o Comparison of emissions at facility level with correction for throughput, if required,
  - o Comparison of emissions at source level or facility level to national or international reference emissions from comparable source or facility, adjusted for size and throughput,
  - o Comparison of measured and calculated emissions.[6]

- Maintain data documentation, including comprehensive documentation of data received through personal communication:
  - o Check that changes in data or methodology are documented

Calculation checks

Calculation checks could be performed for all reported calculations. Elements of calculation checks could include:

- Perform calculation checks by reproducing a representative sample of emissions calculations or building in automated checks such as computational checks for calculations:
  - o Check whether emission units, parameters, and conversion factors are appropriately labeled
  - o Check if units are properly labeled and correctly carried through from beginning to end of calculations
  - o Check that conversion factors are correct
  - o Check the data processing steps (e.g., equations) in the spreadsheets
  - o Check that spreadsheet input data and calculated data are clearly differentiated
  - o Check a representative sample of calculations, by hand or electronically
  - o Check some calculations with abbreviated calculations (i.e., back of the envelope checks)
  - o Check the aggregation of data across source categories, business units, etc.

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[5] Official Journal of the European Union, August 31, 2007. Commission Decision of 18 July 2007, "Establishing guidelines for the monitoring and reporting of GHG emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council. Available at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:229:0001:0085:EN:PDF.

[6] Official Journal of the European Union, August 31, 2007. Commission Decision of 18 July 2007, "Establishing guidelines for the monitoring and reporting of GHG emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council. Available at http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:229:0001:0085:EN:PDF.

- When methods or data have changed, check consistency of time series inputs and calculations.[7]

(F) Reporting Procedure

The following reporting requirements could be considered for a mandatory reporting rule;

a) Where emissions are reported on an annual basis it is not practically possible, in most cases, to determine *when* the fugitive emissions began. Therefore, under these circumstances, annual emissions would be determined assuming that the fugitive emissions were continuous from the beginning of the reporting period or last recorded zero detection in the current reporting period and until the fugitive emissions is repaired or the end of the reporting period.

(b) There are potentially hundreds (and in some cases) thousands of fugitive emissions sources in a facility. Typically, from practical experience in the Natural Gas STAR Program 10 percent of the potential emissions sources have been found to be emitting. Reporting of such large numbers of emissions estimates may not be practical. One way to minimize the reporting burden would be to have facilities report emissions at the individual source type level, i.e. fugitive emissions from each source type can be reported in the aggregate. For example, a facility with multiple reciprocating compressors may report emissions from all reciprocating compressors as an aggregate number. The disadvantage to this approach would be that there would not be a distinction in the reported data between intentional (e.g., vents) and unintentional (e.g., leaks) releases. Although such distinctions may be of interest to the reporter, as different mitigation opportunities may exist for intentional and unintentional releases, it may not be necessary for the integrity of a reporting program, and therefore aggregate reporting may be sufficient.

(c) Due to the point-in-time nature of direct measurements, reports of annual fugitive emissions levels should take into account equipment operating hours according to standard operating conditions and any significant operational interruptions and shutdowns, to convert direct measurement to an annual figure.

(d) The facilities that cross the potential threshold for reporting could report the following information to EPA;

(1) Emissions monitored at an aggregate source level for each facility, separately identifying those emissions that are from standby sources. In several onshore natural gas processing plants CO_2 is being capture for Enhanced Oil Recovery operations. Therefore, these CO_2 emissions may have to be separately accounted for in the reporting.

(2) Activity data, such as the number of sources monitored, for each aggregated source type level for which emissions will be reported.

[7] U.S. EPA 2007. Climate Leaders, Inventory Guidance, Design Principles Guidance, Chapter 7 "Managing Inventory Quality". Available at http://www.epa.gov/climateleaders/documents/resources/design_princ_ch7.pdf.

(G) Verification of Reported Emissions

As part of the data verification requirements, the owner or operator could submit a detailed explanation of how company records of measurements are used to quantify fugitive emissions measurement within 7 days of receipt of a written request from EPA or from the applicable State or local air pollution control agency (the use of electronic mail can be made acceptable).

APPENDIX A: Segregation of Emissions Sources using the Decision Process

The tables provided in this appendix represent the outcome of the decision process used to identify a starting list of potential sources that can be included in the proposed rule.

Inventory of Methane Emissions from Natural Gas Systems (Year 2006)

Note: Cells Highlighted in "yellow" represent sources that fall over the threshold for either 1% of total emissions (3597 MMcf/year) or emissions factor (100 Mcf/year)

Cells highlighted in "pink" represent sources that were included over riding the decision tree process

PRODUCTION	Total Emissions Nationally (MMcf/year)	Emissions per unit (Mcf/year)	Preferred Estimation Methodology	Decision Process Outcome	Reduction Technology Available (Y/N)
		Production EFs are for Rocky Mountain Region	Measurement Continuous Measurement Periodic Engineering (Calculation) Emission Factors (Calculation)	I-include; PI-probably include; CI-consider including; ET-excluded with tech; EX-excluded	
Normal Fugitives					
Gas Wells					
Non-associated Gas Wells (less Unconventional)	2,682	13	Measurement Periodic	ET	Y
Unconventional Gas Wells	69	3	Measurement Periodic	ET	Y
Field Separation Equipment					
Heaters	1,463	21	Measurement Periodic	ET	Y
Separators	4,718	45	Measurement Periodic	PI	Y
Dehydrators	1,297	33	Measurement Periodic	ET	Y
Meters/Piping	4,556	19	Measurement Periodic	PI	Y
Gathering Compressors					
Small Reciprocating Comp.	2,926	98	Measurement Periodic	ET	Y
Large Reciprocating Comp.	664	5,550	Measurement Periodic	PI	Y
Large Reciprocating Stations	45	3,010	Measurement Periodic	PI	Y
Pipeline Leaks	8,087	19	Measurement Periodic	PI	Y
Vented and Combusted					
Drilling and Well Completion					
Completion Flaring	0	0.73	Engineering	ET	Y
Well Drilling	96	3	Measurement Continuous/Engineering	EX	N
Coal Bed Methane					
Powder River (Gg/gallon water drainage)	2,924	1.9831E-09	Measurement Continuous/Engineering	ET	Maybe
Black Warrior (Gg/well)	543	0.0023	Measurement Continuous/Engineering	ET	Maybe
Normal Operations					
Pneumatic Device Vents	52,421	126	Measurement Periodic/Emission Factors	PI	Y
Chemical Injection Pumps	2,814	91	Engineering	ET	Y
Kimray Pumps (Mcf/MMscf)	11,572	1	Engineering	PI	Y
Dehydrator Vents (Mcf/MMscf)	3,608	0	Engineering	PI	Y
Condensate Tank Vents					
Condensate Tanks without Control Devices (Mcf/bbl)	1,225	0.02	Engineering	I	Y
Condensate Tanks with Control Devices (Mcf/bbl)	245	0.00	Engineering	I	N
Compressor Exhaust Vented					
Gas Engines (scf/HPhr)	11,680	0.24	Measurement Continuous/Emission Factors	I	Maybe
Well Workovers					
Gas Wells	47	2	Engineering	I	Y
Well Clean Ups (LP Gas Wells)	9,008	50	Engineering	I	Y
Blowdowns					
Vessel BD	31	0.08	Engineering	EX	N
Pipeline BD	129	0.31	Engineering	ET	Y
Compressor BD	113	4	Engineering	ET	Y
Compressor Starts	253	8	Engineering	ET	Y
Upsets					
Pressure Relief Valves	29	0	Not Practical	EX	N
Mishaps	70	1	Not Practical	EX	N
Offshore	0				
Shallow water Gas Platforms (GoM and Pacific)	12,621	7,000	Measurement Periodic	PI	Y
Deepwater Gas Platforms (GoM and Pacific)	630	29,000	Measurement Periodic	PI	Y

Inventory of Methane Emissions from Natural Gas Systems (Year 2006)

Note: Cells Highlighted in "yellow" represent sources that fall over the threshold for either 1% of total emissions (3597 MMcf/year) or emissions factor (100 Mcf/year)
Cells highlighted in "pink" represent sources that were included over riding the decision tree process

GAS PROCESSING PLANTS		Total Emissions Nationally (MMcf/year)	Emissions per unit (Mcf/year)	Preferred Estimation Methodology Measurement Continuous Measurement Periodic Engineering (Calculation) Emission Factors (Calculation)	Decision Process Outcome I-include; PI-probably include; CI-consider including; ET-excluded with tech; EX-excluded	Reduction Technology Available (Y/N)
Normal Fugitives						
Plants		1,634	**2,886**	Measurement Periodic	PI	Y
Recip. Compressors		**17,351**	**4,087**	Measurement Periodic	PI	Y
Centrifugal Compressors		**5,837**	**7,749**	Measurement Periodic	PI	Y
Vented and Combusted						
Normal Operations						
Compressor Exhaust						
Gas Engines	(scf/HPhr)	**6,913**	0.24	Measurement Continuous/Emission Factors	I	Maybe
Gas Turbines	(scf/HPhr)	195	0.01	Measurement Continuous/Emission Factors	I	Maybe
AGR Vents		643	**2,220**	Engineering	PI	Y
Kimray Pumps	(Mcf/MMscf)	177	0.18	Engineering	ET	Y
Dehydrator Vents	(Mcf/MMscf)	1,088	0.12	Engineering	ET	Y
Pneumatic Devices	(Mcf/plant)	93	**165**	Engineering	PI	Y
Routine Maintenance						
Blowdowns/Venting	(Mcf/ plant)	2,299	**4,060**	Engineering	PI	Y
TRANSMISSION AND STORAGE						
Fugitives						
Pipeline Leaks		166	0.57	Measurement Periodic/ Engineering	ET	Y
Compressor Stations (Transmission)						
Station		**5,619**	**3,204**	Measurement Periodic	PI	Y
Recip Compressor		**38,918**	**5,550**	Measurement Periodic	PI	Y
Centrifugal Compressor		**7,769**	**11,061**	Measurement Periodic	PI	Y
Compressor Stations (Storage)						
Station		2,801	**7,850**	Measurement Periodic	PI	Y
Recip Compressor		**8,093**	**7,707**	Measurement Periodic	PI	Y
Centrifugal Compressor		1,149	**11,159**	Measurement Periodic	PI	Y
Wells (Storage)		695	42	Measurement Periodic	ET	Y
M&R (Trans. Co. Interconnect)		**3,798**	**1,454**	Measurement Periodic	PI	Y
M&R (Farm Taps + Direct Sales)		853	11	Measurement Periodic	ET	Y
Vented and Combusted						
Normal Operation						
Dehydrator vents (Transmission)	(scf/MMscf)	105	94	Engineering	ET	Y
Dehydrator vents (Storage)	(scf/MMscf)	217	**117**	Engineering	PI	Y
Compressor Exhaust						
Engines (Transmission)	(scf/HPhr)	**10,820**	0.24	Measurement Continuous/Emission Factors	I	Maybe
Turbines (Transmission)	(scf/HPhr)	61	0.01	Measurement Continuous/Emission Factors	I	Maybe
Engines (Storage)	(scf/HPhr)	1,092	0.24	Measurement Continuous/Emission Factors	I	Maybe
Turbines (Storage)	(scf/HPhr)	9	0.01	Measurement Continuous/Emission Factors	I	Maybe
Generators (Engines)	(scf/HPhr)	529	0.24	Measurement Continuous/Emission Factors	I	Maybe
Generators (Turbines)	(scf/HPhr)	0	0.01	Measurement Continuous/Emission Factors	I	Maybe
Pneumatic Devices Trans + Stor						
Pneumatic Devices Trans		**11,393**	**162**	Engineering/Emission Factors	PI	Y
Pneumatic Devices Storage		2,318	**162**	Engineering/Emission Factors	PI	Y
Routine Maintenance/Upsets						
Pipeline venting		9,287	32	Engineering	ET	Y
Station venting Trans + Storage						
Station Venting Transmission		**7,645**	**4,359**	Engineering	PI	Y
Station Venting Storage		1,555	**4,359**	Engineering	PI	Y

Inventory of Methane Emissions from Natural Gas Systems (Year 2006)

Note: Cells Highlighted in "yellow" represent sources that fall over the threshold for either 1% of total emissions (3597 MMcf/year) or emissions factor (100 Mcf/year)
Cells highlighted in "pink" represent sources that were included over riding the decision tree process

LNG STORATE AND TERMINALS		Total Emissions Nationally (MMcf/year)	Emissions per unit (Mcf/year)	Preferred Estimation Methodology Measurement Continuous Measurement Periodic Engineering (Calculation) Emission Factors (Calculation)	Decision Process Outcome I-include; PI-probably include; CI-consider including; ET-excluded with tech; EX-excluded	Reduction Technology Available (Y/N)
LNG Storage						
LNG Stations		552	7,850	Measurement Periodic	PI	Y
LNG Reciprocating Compressors		2,084	7,707	Measurement Periodic	PI	Y
LNG Centrifugal Compressors		715	11,159	Measurement Periodic	PI	Y
LNG Compressor Exhaust						
LNG Engines	(scf/HPhr)	172	0.24	Measurement Continuous/Emission Factors	I	Maybe
LNG Turbines	(scf/HPhr)	1	0.01	Measurement Continuous/Emission Factors	I	Maybe
LNG Station venting		306	4,359	Engineering	PI	N
LNG Import Terminals						
LNG Stations		22	7,850	Measurement Periodic	PI	Y
LNG Reciprocating Compressors		105	7,707	Measurement Periodic	PI	Y
LNG Centrifugal Compressors		27	11,159	Measurement Periodic	PI	Y
LNG Compressor Exhaust						
LNG Engines	(scf/HPhr)	586	0.24	Measurement Continuous/Emission Factors	I	Maybe
LNG Turbines	(scf/HPhr)	3	0.01	Measurement Continuous/Emission Factors	I	Maybe
LNG Station venting		12	4,359	Engineering	PI	N
DISTRIBUTION						
Mains - Unprotected steel		6,515	110	Emission Factors	CI	Y
Mains - Protected steel		1,422	3	Emission Factors	ET	Y
Mains - Plastic		6,871	10	Emission Factors	CI	Y
Total Pipeline Miles						
Services - Unprotected steel		7,322	2	Emission Factors	CI	Y
Services Protected steel		2,863	0.18	Emission Factors	ET	Y
Services - Plastic		315	0.01	Emission Factors	ET	Y
Services - Copper		47	0.25	Emission Factors	ET	Y
Total Services						
Meter/Regulator (City Gates)						
M&R >300		5,037	1,575	Measurement Periodic	PI	Y
M&R 100-300		10,322	837	Measurement Periodic	PI	Y
M&R <100		249	38	Measurement Periodic	ET	Y
Reg >300		5,237	1,383	Measurement Periodic	PI	Y
R-Vault >300		25	11	Measurement Periodic	ET	Y
Reg 100-300		4,025	355	Measurement Periodic	PI	Y
R-Vault 100-300		8	2	Measurement Periodic	ET	Y
Reg 40-100		306	9	Measurement Periodic	ET	Y
R-Vault 40-100		23	0.76	Measurement Periodic	ET	Y
Reg <40		17	1	Measurement Periodic	ET	Y
Customer Meters						
Residential		5,304	0.14	Measurement Periodic	PI	Y
Commercial/Industry		203	0.05	Measurement Periodic	ET	Y
Vented						
Rountine Maintenance						
Pressure Relief Valve Releases	(Mcf/mile)	63	0.05	Not Practical	EX	N
Pipeline Blowdown	(Mcf/mile)	122	0.10	Engineering	ET	Y
Upsets						
Mishaps (Dig-ins)		1,907	2	Not Practical	EX	N

Inventory of Methane Emissions from Petroleum Systems (Year 2006)

Note: Cells Highlighted in "yellow" represent sources that fall over the threshold for either 1% of total emissions (704 MMcf/year) or emissions factor (100 Mcf/year)

Cells highlighted in "pink" represent sources that were included over riding the decision tree process

Emission Source		Total Emissions Nationally (MMcf/year)	Emissions per unit (Mcf/year)	Preferred Estimation Methodology Measurement Continuous Measurement Periodic Engineering (Calculation) Emission Factors (Calculation)	Decision Tree I-include; PI-probably include; CI-consider including; ET-excluded with tech; EX-excluded	Reduction Technology Available (Y/N)
Production						
Vented Emissions:						
Oil Tanks	(scf/bbl of crude)	7,171	5	Measurement Periodic	PI	Y
Pneumatic Devices, High Bleed		16,067	121	Engineering	PI	Y
Pneumatic Devices, Low Bleed		4,696	19	Engineering	PI	Y
Chemical Injection Pumps		2,429	91	Engineering	PI	Y
Vessel Blowdowns		14	0.08	Engineering	EX	N
Compressor Blowdowns		9	4	Engineering	ET	Y
Compressor Starts		20	8	Engineering	ET	Y
Stripper wells		752	2	Measurement Periodic	PI	Y
Well Completion Venting		9	1		EX	N
Well Workovers		4	0.10		EX	N
Pipeline Pigging		0.00	1	Engineering	ET	Y
OCS Offshore Platforms, Shallow water oil		29,275	20,000	Measurement Periodic	PI	Y
OCS Offshore Platforms, Deep water oil		2,202	95,000	Measurement Periodic	PI	Y
Fugitive Emissions:						
Oil Wellheads (heavy crude)		1	0.05	Measurement Periodic	ET	Y
Oil Wellheads (light crude)		1,016	6	Measurement Periodic	PI	Y
Separators (heavy crude)		1	0.06	Measurement Periodic	ET	Y
Separators (light crude)		471	5	Measurement Periodic	ET	Y
Heater/Treaters (light crude)		494	7	Measurement Periodic	ET	Y
Headers (heavy crude)		0.37	0.03	Measurement Periodic	ET	Y
Headers (light crude)		161	4	Measurement Periodic	ET	Y
Floating Roof Tanks		8	338	Measurement Periodic	PI	Y
Compressors		86	37	Measurement Periodic	ET	Y
Large Compressors		0.00	5,971	Measurement Periodic	PI	Y
Sales Areas	(Mcf/loading)	63	0.04	Measurement Periodic	ET	Y
Pipelines		0.00	0.00	Measurement Periodic	ET	Y
Well Drilling		0.00	0.00		EX	N
Battery Pumps		13	0.09		ET	Y
Combustion Emissions:						
Gas Engines	(scf CH4/HP-hr)	3,564	0.24	Monitoring (Measurement Continuous)	I	Y
Heaters	(scf CH4/bbl)	1	1		EX	N
Well Drilling		34	2		EX	N
Flares	(scf/ Mcf flared	3	20		I	Y
Process Upset Emissions:						
Pressure Relief Valves		5	0.03		EX	N
Well Blowouts Onshore		116	2,500	Engineering	PI	N

Inventory of Methane Emissions from Petroleum Systems (Year 2006)

Note: Cells Highlighted in "yellow" represent sources that fall over the threshold for either 1% of total emissions (704 MMcf/year) or emissions factor (100 Mcf/year)
Cells highlighted in "pink" represent sources that were included over riding the decision tree process

Emission Source	Total Emissions Nationally (MMcf/year)	Emissions per unit (Mcf/year)	Preferred Estimation Methodology: Measurement Continuous, Measurement Periodic, Engineering (Calculation), Emission Factors (Calculation)	Decision Tree: I-include; PI-probably include; CI-consider including; ET-excluded with tech; EX-excluded	Reduction Technology Available (Y/N)
Transportation					
Vented Emissions:					
Tanks (scf CH4/yr/bbl of crude delivered to refineries)	115	0.02		EX	Y
Truck Loading (scf CH4/yr/bbl of crude transported by truck)	30	1		EX	
Marine Loading (scf CH4/1000 gal.crude marine loadings)	57	3		EX	
Rail Loading (scf CH4/yr/bbl of crude transported by rail)	2	1		EX	
Pump Station Maintenance	0.02	0.04		EX	
Pipeling Pigging	14	0.04		EX	Y
Fugitive Emissions:					
Pump Stations	1	0.03		EX	N
Pipelines	0.00	0.00		EX	N
Floating Roof Tanks	49	59		EX	N
Combustion Emissions:					
Pump Engine Drivers (scf CH4/hp-hr)	NA	0.24		EX	Y
Heaters (scf CH4/bbl.burned)	NA	1		EX	Y
Refineries					
Vented Emissions:					
Tanks	15	21	Engineering	I	Y
System Blowdowns	**761**	**137**		PI	Y
Asphalt Blowing	472	**2,555**		PI	
Fugitive Emissions:					
Fuel Gas System (Mcf /refinery)	64	**439**		PI	N
Floating Roof Tanks (Mcf CH4/floating roof tank/)	0.45	1	Engineering	I	N
Wastewater Treating	10	2		EX	N
Cooling Towers	13	2		EX	N
Combustion Emissions:					
Atmospheric Distillation	21	4		EX	Y
Vacuum Distillation	9	4		EX	Y
Thermal Operations	5	6		EX	Y
Catalytic Cracking	10	5		EX	Y
Catallytic Reforming	8	7		EX	Y
Catalytic Hydrocracking	4	7		EX	Y
Hydrorefining	2	2		EX	Y
Hydrotreating	24	6		EX	Y
Alkylation/Polymerization	5	13		EX	Y
Aromatics/Isomeration	1	2		EX	Y
Lube Oil Processing	0.00	0.00		EX	Y
Engines (scfCH4/hp-hr)	7	0.01	Engineering	I	Y
Flares	1	0.19	Engineering	I	Y

APPENDIX B: Glossary

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Acid gas means hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal process.

Acid gas removal unit (AGR) means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents, such as liquid absorbents, solid adsorbents, or membrane separators.

Acid gas removal vent stack fugitive emissions mean the acid gas (typically CO_2 and/or H_2S) separated from the acid gas absorbing medium (most commonly an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

Actual conditions mean temperature, pressure and volume at measurement conditions of natural gas.

Actuation means, for the purposes of this rule, an event in which a natural gas pneumatically driven valve is opened and/or closed by release of natural gas pressure to the atmosphere.

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e. high non-combustible component content).

Ambient temperature means the surrounding temperature to a process or stream; often times the atmospheric temperature.

Anti-static wrap means wrap used to assist the process of ensuring that all fugitive emissions from a single source are captured and directed to a measurement instrument.

Backpressure means impeding the natural atmospheric release of fugitive emissions by enclosing the release with a lower capacity sampling device and altering natural flow.

Barometric pressure means the pressure of the atmosphere at the given altitude and time, as measured by a barometer.

Bleed rate means the rate at which natural gas flows continuously or intermittently from a process measurement instrument to a valve actuator controller where it is vented (bleeds) to the atmosphere.

Blowdown means manual or automatic opening of valves to relieve pressure and or release natural gas from but not limited to process vessels, compressors, storage vessels or pipelines by venting natural gas to the atmosphere or a flare. This practice is often implemented prior to shutdown or maintenance.

Blowdown vent stack fugitive emissions mean natural gas released due to maintenance and/or blowdown operations including but not limited to compressor blowdown and Emergency Shut-Down system testing.

Boil-off gas means natural gas that vaporizes off of liquefied natural gas in storage tanks.

Calibrated bag means a flexible, non-elastic bag of a calibrated volume that can be quickly affixed to a fugitive emitting source such that the fugitive emissions inflate the bag to its calibrated volume.

Centrifugal compressor means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case,that operate mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor dry seals fugitive emissions mean natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor wet seals mean a series of rings around the compressor shaft where it exits the compressor case, that use oil circulated under high pressure between the rings to prevent natural gas from escaping to the atmosphere.

Centrifugal compressor wet seals fugitive emissions mean natural gas released from the seal face around the rotating shaft where it exits one or both ends of the compressor case PLUS the natural gas absorbed in the circulating seal oil and vented to the atmosphere from a seal oil degassing vessel or sump before the oil is re-circulated, or from a seal oil containment vessel vent.

Close-range means, for the purposes of this rule, safely accessible within the operator's arm's reach from the ground or stationary platforms.

Cold fugitive emissions mean an emissions stream that is low enough in temperature (i.e. less than 140 degrees Fahrenheit) to be safely directly measured by a person.

Component means but is not limited to each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Comprehensive emissions detection survey means effort made with rule specified and calibrated instruments, to inspect all potential fugitive emission sources required under this rule, and detect actual emissions, including direct measurement of fugitive emissions found or acquisition of operating and facility date necessary for engineering estimates including process simulation modeling of emissions.

Compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas (i.e. compression ratio higher than 1.5).

Compressor fugitive emissions mean natural gas emissions from all components in close physical proximity to compressors where mechanical and thermal cycles may cause elevated emission rates, including but not limited to open-ended blowdown vent stacks, piping and tubing connectors and flanges, pressure relief valves, pneumatic starter open-ended lines, instrument connections, cylinder valve covers, and fuel valves.

Condensate means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

Connector means but is not limited to flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

Control method means any equipment used for recovering and/or oxidizing air emissions of methane. Such equipment includes, but is not limited to, vapor recovery systems, absorbers, carbon dioxide adsorbers, condensers, incinerators, flares, catalytic oxidizers, boilers, and process heaters.

Correction factor for flow meters means a calibration factor that is applied to the direct instrument reading to convert the value to a more correct value.

Crude oil means any of the naturally occurring liquids and semi-solids found in rock formations composed of complex mixtures of hydrocarbons ranging from one to hundreds of carbon atoms in straight and branched chains and rings.

Dehydrator means, for the purposes of this rule, a device in which a liquid absorbent (including but not limited to desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

Dehydrator vent stack fugitive emissions mean natural gas released from natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

De-methanizer means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (ethane, propane, butane, pentane-plus) in feed natural gas stream.

Downstream of de-methanizer means any process stream or equipment containing a process stream that has passed through a de-methanizer at natural gas processing facilities.

Engineering estimation means an estimate of fugitive emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

Equipment means but is not limited to each pump, compressor, pipe, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, surge control vessel, tank, vessel, and instrumentation system in natural gas or liquid service; and any control devices or systems referenced by this subpart.

Emissions Source see component, qualified to be those components that contain and potentially can release methane to the atmosphere.

Equipment chambers mean the total natural gas-containing volume within an equipment between the equipment isolation valves.

Flare stack means a device used to provide a safe means of combustible natural gas disposal from routine operations, upsets, or emergencies via combustion of the natural gas in an open, normally elevated flame.

Flare combustion efficiency means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip, assumed 95% for non-aspirated field flares and 98% for steam or air asperated flares.

Flare stack fugitive emissions means the CH_4 and CO_2 content of that portion of natural gas (typically 5% in non-aspirated field flares and 2% in steam or air asperated flares) that passes through flares un-combusted and the total CO_2 emissions of that portion of the natural gas that is combusted.

Fractionation of natural gas liquids means the process by which saturated hydrocarbons are removed from natural gas and separated by boiling point into distinct products, or "fractions," such as propane, butane, and ethane.

Fugitive emissions means unintentional equipment emissions, and in context of this rule intentional or designed releases, of methane and/or carbon dioxide containing natural gas or hydrocarbon gas(not including combustion flue gas) from emissions sources including, but not limited to, open ended lines, equipment connections or seals to the atmosphere. In the context of this rule, fugitive emissions also mean CO_2 emissions resulting from combustion of natural gas in flares.

Fugitive emissions detection means the process of identifying natural gas emitting equipment, components, and other point sources, either intentional or unintentional.

Fugitive emissions detection instruments mean any device or instrument that has been approved for fugitive emissions detection in this rule, namely infrared fugitive emissions detection instruments, OVAs, and TVAs.

Fugitive emissions measurement means the process of using measuring instruments in direct contact with the natural gas fugitive emissions to quantify the mass or volumes emitted from detected point sources.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gathering and boosting station means a station used to gather natural gas from well or field pipelines for delivery to a natural gas processing facilities or central point. Stations may also provide compression, dehydration, and/or treating services.

High volume sampler means an atmospheric emissions measurement device that captures emissions from a source in a calibrated air intake and uses dual hydrocarbon sensors and other devices to measure the flow rate and combustible hydrocarbon concentrations of the fugitive emission such that the quantity of emissions is determined.

Hot wire anemometer means a meter that measures gas velocity by measuring the heat convected by the gas from a hot wire core of the meter. The hot wire is either heated using a constant source of current or kept at a constant temperature. The measurements are made by traversing the meter across the cross section of the conduit carrying the gas and profiling the flow across the cross section. The gas velocity is estimated using a standard correlation of gas velocities to wire temperatures or current consumption.

Infrared remote fugitive emissions detection instrument means an instrument that detects infrared light in the narrow wavelength range absorbed by light hydrocarbons including methane, and presents a signal (sound, digital or visual image) indicating the presence of methane and other light hydrocarbon vapor emissions in the atmosphere; for the purpose of this rule, it must detect the presence of methane.

Liquefied natural gas (LNG) means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

Liquefied natural gas import and export facilities mean onshore and/or offshore facilities that send out exported or receive imported liquefied natural gas, store it in storage tanks, re-gasify it, and deliver re-gasified natural gas to natural gas transmission or distribution systems. The facilities include tanker unloading equipment, liquefied natural gas transportation pipelines, pumps, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

LNG import and export facility fugitive emissions mean natural gas releases from valves, connectors, storage tanks, flanges, open-ended lines, pressure relief valves, boil-off-gas recovery, send outs (pumps and vaporizers), packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

Liquefied natural gas storage facilities means an onshore facility that stores liquefied natural gas in above ground storage vessels. The facility may include equipment for liquefying natural gas, compressors to liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

LNG storage station fugitive emissions mean natural gas releases from valves, connectors, flanges, open-ended lines, storage tanks, pressure relief valves, liquefaction process units, packing and gaskets. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

Mass emissions mean fugitive emissions reported in mass units such as kilograms or tonnes.

Meter means a device that measures gas flow rate from a fugitive emissions source or through a conduit by detecting a condition (pressure drop, spin induction, temperature loss, electronic signal) that varies in proportion to flow rate or measures gas velocity in a manner that can calculate flow rate.

Mole percent means the proportion of a chemical species in a mixture that represents the ratio of the number of molecules of that species per total number of all molecules of all chemical species in the mixture.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this subpart, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

Natural gas driven pneumatic manual valve actuator device means valve control devices that use pressurized natural gas to provide the energy required for an operator to manually open, close, or throttle a liquid or gas stream. Typical manual control applications include, but are not limited to, equipment isolation valves, tank drain valves, pipeline valves.

Natural gas driven pneumatic manual valve actuator device fugitive emissions means natural gas released due to manual actuation of natural gas pneumatic valve actuation devices, including, but not limited to, natural gas diaphragm and pneumatic-hydraulic valve actuators.

Natural gas driven pneumatic pump means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

Natural gas driven pneumatic pump fugitive emissions means natural gas released from pumps that are powered or assisted by pressurized natural gas.

Natural gas driven pneumatic valve bleed device means valve control devices that use pressurized natural gas to transmit a process measurement signal to a valve actuator to automatically control the valve opening. Typical bleeding process control applications include, but are not limited to, pressure, temperature, liquid level, and flow rate regulation.

Natural gas driven pneumatic valve bleed devices fugitive emissions means natural gas continuous or intermittent release from automatic process control loops including the natural gas pressure signal flowing from a process measurement instrument (e.g. liquid level, pressure, temperature) to a process control instrument which activates a process control valve actuator.

Natural gas liquids means the liquid hydrocarbons, such as ethane, propane, butane, pentane, and natural gasoline that are extracted from natural gas produced from crude oil and natural gas wells.

Natural gas processing facilities means any processing site engaged in the extraction of natural gas liquids from produced natural gas, which may also include fractionation of mixed Natural Gas Liquids (NGL) to natural gas products, removal of contaminants such as but not limited to carbon dioxide, sulfur compounds, nitrogen, helium, and water. In addition, processing facilities encompass gathering and boosting stations that include equipments that phase-separate natural gas liquids from natural gas, dehydrate the natural gas, and transport the natural gas to transmission pipelines or to a processing facility with fractionation equipment.

Natural gas products means products produced for consumers from natural gas processing facilities including, but not limited to, ethane, propane, butane, iso-butane, and pentanes-plus.

Natural gas transmission compression facility means any permanent combination of compressors that move natural gas at increased pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage facilities. In addition, transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and storage of water and hydrocarbon liquids.

Non-pneumatic pump means any pump that is not pneumatically powered with pressurized gas of any type, such as natural gas, air, or nitrogen.

Non-pneumatic pump fugitive emissions means natural gas released through connectors and flanges of electric motor or engine driven pumps.

Non-steam aspirated flare means a flare where natural gas burns at the tip with natural induction of air (and relatively lower combustion efficiency as may be evidenced by smoke formation).

Offshore means tidal-affected borders of the U.S. lands, both state and Federal, adjacent to oceans, bays, lakes or other normally standing water.

Offshore petroleum and natural gas production facilities means any platform structure, floating in the ocean or lake, fixed on ocean or lake bed, or located on artificial islands in the ocean or lake, that houses equipment to extract hydrocarbons from ocean floor and transports it to storage or transport vessels or onshore. In addition, offshore production facilities may include equipments for separation of liquids from natural gas components, dehydration of natural gas, extraction of H_2S and CO_2 from natural gas, crude oil and condensate storage tanks, both on the platform structure and floating storage tanks connected to the platform structure by a pipeline, and compression or pumping of hydrocarbons to vessels or onshore. The facilities under consideration are located in both State administered waters and Mineral Management Services administered Federal waters.

Offshore platform pipeline fugitive emissions means natural gas above the water line released from piping connectors, pipe wall ruptures and holes in natural gas and crude oil pipeline surfaces on offshore production facilities.

Open-ended line fugitive emissions means natural gas released from pipes or valves open on one end to the atmosphere that are intended to periodically vent or drain natural gas to the atmosphere but may also leak process gas or liquid through incomplete valve closure including valve seat obstructions or damage.

Open-ended valve or Lines (OELs) means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operating characteristics means normal flow rates, temperatures, pressures, stream compositions typical of steady state or majority of operating time conditions.

Operating hours means the duration of time in which a process or process unit is utilized; this excludes shutdown, maintenance, and standby.

Operating pressure means the containment pressure that characterizes the normal state of gas and/or liquid inside a particular process, pipeline, vessel or tank.

Optimal operating conditions of fugitive emissions detection instruments means 1) for IR emission detection intruments, weather, ambient light and reflective background conditions that produce a strong signal in response to the presence of methane; and 2) for OVA and TVA instruments, non-interference with air intake probe by atmospheric fluids or materials such as rain, snow or dust.

Organic monitoring device means an instrument used to indicate the concentration level of organic compounds exiting a control device based on a detection principle such as IR, photoionization, or thermal conductivity.

Organic vapor analyzer (OVA) means an organic monitoring device (as defined previously) that uses a flame ionization detector to measure the concentrations in air of combustible organic vapors from 9 to 10,000 parts per million sucked into the probe.

Petroleum and natural gas industry means all companies, endeavors and facilities involved in finding, accessing, producing, transporting, and processing fossil crude oil and natural gas to produce and deliver products suitable for distribution to consuming customers.

Pitot tube means a right angled tube that measures the pressure differential between the interior of the pitot tube and the surrounding air to measure velocity of gas. The measurements are made by traversing the meter across the cross section of the conduit carrying the gas and profiling the flow across the cross section. The gas velocity is estimated using a standard correlation of gas velocities to pressure differentials.

Platform fugitive emissions means natural gas released from equipment and equipment components including valves, pressure relief valves, connectors, tube fittings, open-ended lines, ports, and hatches. This does not include fugitive emissions from equipment and components reported elsewhere for this rule.

Pressure relief device or pressure relief valve or pressure safety valve means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process equipment. A common pressure relief device is but not limited to a spring-loaded pressure relief valve. Devices that are actuated either by a pressure of less than or equal to 2.5 psig or by a vacuum are not pressure relief devices.

Processing facility fugitive emissions means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system fugitive emissions, packing and gaskets in natural gas processing facilities. This does not include fugitive emissions from equipment and components reported elsewhere for this rule, such as compressor fugitive emissions; acid gas removal, blowdown, wet seal oil degassing, and dehydrator vents; and flare stacks.

Pump means a device used to raise, drive, or increase pressure and flow of liquid streams.

Pump seals means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

Pump seal fugitive emissions means natural gas released from the seal face between the pump internal chamber and the atmosphere.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Reciprocating compressor rod packing fugitive emissions means natural gas released from a connected tubing vent and/or around a piston rod where it passes through the rod packing case. It also includes emissions from uncovered distance piece, rod packing flange (on each cylinder), any packing vents, cover plates (on each cylinder), and the crankcase breather cap.

Re-condenser means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

Re-gasification means the process of vaporizing liquefied natural gas to gaseous phase natural gas.

Representative gas for flare stacks means a sample natural gas stream that is closest in composition to the expected average composition of flared natural gas streams.

Residue gas means natural gas from which natural gas processing facilities liquid products and, in some cases, nonhydrocarbon components have been extracted.

Rotameter means a flow meter in which gas flow rate upward through a tapered tube lifts a "float bob" to an elevation related to the gas flow rate indicated by etched calibrations on the wall of the tapered tube.

Sensor means a device that measures a physical quantity/quality or the change in a physical quantity/quality, such as temperature, pressure, flow rate, pH, or liquid level.

Shutdown means the cessation of operation of an affected source under this subpart, or equipment required or used solely to comply with this subpart, for purposes including, but not limited to, standby for future operation (either pressurized or depressureized), periodic maintenance, replacement of equipment, or repair.

Simulation software means a calibrated, empirical computer program that uses physical parameters and scientific laws to numerically simulate the performance variables of a physical process, outputting such parameters as emission rates from which methane emissions can be estimated.

Site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically located.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Source see “Emissions Source”.

Standard conditions or standard temperature and pressure (STP) means 60 degrees Fahrenheit and 14.7 pounds per square inch absolute.

Standby means for an equipment to be in a state ready for operation, but not operating.

Steady fugitive emissions means fugitive emission characterized by a nearly constant and steady release rate.

Steam aspirated flare means steam injected into the flare burner tip to induce air mixing with the hydrocarbon fuel to promote more complete combustion as indicated by lack of smoke formation.

Storage station fugitive emissions means natural gas released from all components including valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system emissions, packing and gaskets in natural gas storage station. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule.

Storage tank means other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

Storage tank fugitive emissions means natural gas vented when it flashes out of liquids; this occurs when liquids are transferred from higher pressure and temperature conditions upstream, plus working losses from liquid level increases and decreases during filling and draining and standing losses (breathing losses) from diurnal temperature changes and barometric pressure changes expanding and contracting the vapor volume of a tank.

Storage wellhead fugitive emissions means natural gas released from storage station wellhead components including but not limited to valves, OELs, connectors, flanges, and tube fittings.

Stripping gas for glycol dehydrator means natural gas injected into wet glycol in the reboiler to cause absorbed water to vaporize at lower temperatures.

Sub-surface or subsurface facility means for the purposes of this rule, a natural gas facility, such as a pipeline and metering and regulation station in a closed vault below the land surface of the Earth.

Tanker means ocean-going vessel that transports crude oil, liquefied natural gas, or petroleum products.

Tanker unloading means pumping of liquid hydrocarbon (e.g. crude oil, LNG) from an ocean-going tanker or barge to shore storage tanks.

Toxic vapor analyzer (TVA) means an organic monitoring device that uses a flame ionization detector and photoionization detector to measure the concentrations in air of combustible organic vapors from 9 parts per million and exceeding 10,000 parts per million sucked into the probe.

Trained technician means a person who has completed a vendor provided or equivalent training program and demonstrated proficiency to use specific equipment for its intended purpose, such as high volume sampler for the purposes of this rule.

Transmission pipeline means high pressure cross country pipeline transporting saleable quality natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

Transmission compressor station fugitive emissions means natural gas released from all components including but not limited to valves, flanges, connectors, open-ended lines, pump seals, ESD (emergency shut-down) system emissions, packing and gaskets in natural gas transmission compressor stations. This does not include fugitive emissions from equipment and equipment components reported elsewhere for this rule, such as compressor fugitive emissions.

Turbine meter means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

Underground natural gas storage facility means a subsurface facility, including but not limited to depleted gas or oil reservoirs and salt dome caverns, utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at an natural gas underground storage facility include, but are not limited to, compression, dehydration and flow measurement. The storage facility also includes all the wellheads connected to the compression units located at the facility.

Upstream of de-methanizer means any process stream or equipment containing a process stream that has not passed through a de-methanizer at natural gas processing facilities (i.e. natural gas rich in non-methane hydrocarbons).

Valve means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices; and that is used for routing the gas back into the process as a product and/or fuel.

Vaporization unit means a process unit that performs controlled heat input to vaporize liquefied natural gas to supply transmission and distribution pipelines, or consumers with natural gas.

Very high degree of accuracy means three significant digits of numerical determination (e.g. 0.034 or 56.3).

Wellhead means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/ or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

Wet natural gas means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

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